PACIFIC GAS & ELECTRIC CO
Form 10-K/A
June 30, 2003

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

Amendment No. 3

(Mark One)

ý **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2002

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _______ to _______

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

Pacific Gas and Electric Company	PG&E Corporation
77 Beale Street	One Market, Spear Tower
P.O. Box 770000	Suite 2400
San Francisco, California	San Francisco, California
(Address of principal executive offices)	**(Address of principal executive offices)**
94177	94105
(Zip Code)	**(Zip Code)**
(415) 973-7000	(415) 267-7000
(Registrant's telephone number, including area code)	**(Registrant's telephone number, including area code)**

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

Title of Each Class	Name of Each Exchange on Which Registered
PG&E Corporation	
Common Stock, no par value	New York Stock Exchange and Pacific Exchange
Preferred Stock Purchase Rights	
Pacific Gas and Electric Company	
First Preferred Stock, cumulative, par value $25 per share:	American Stock Exchange and Pacific Exchange
Redeemable: 7.04%, 5% Series A, 5%, 4.80%, 4.50%, 4.36%	

Title of Each Class	Name of Each Exchange on Which Registered
Mandatorily Redeemable: 6.57%, 6.30%	
Nonredeemable: 6%, 5.50%, 5%	
7.90% Deferrable Interest Subordinated Debentures	American Stock Exchange and Pacific Exchange

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes ý No o

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 28, 2002, the last business day of the second fiscal quarter:

PG&E Corporation Common Stock	$6,559 million
Common Stock outstanding as of February 1, 2003:	
PG&E Corporation:	407,576,505
Pacific Gas and Electric Company:	Wholly owned by PG&E Corporation

Explanatory Note

Subsequent to the issuance of PG&E Corporation's 2002 Consolidated Financial Statements, management discovered a misclassification of certain offsetting revenues and expenses within the discontinued operations of PG&E NEG. As a result, PG&E Corporation's Note 6 of the Notes to the Consolidated Financial Statements has been revised to reflect the reclassification. The reclassification resulted in a decrease in 2002 Operating Revenues in the table in Note 6 from $1,289 million to $822 million and a similar decrease in Operating Expenses Cost of Commodity Sales and Fuel from $993 million to $526 million. The reclassification did not result in a change in the Consolidated Statement of Operations, the Consolidated Balance Sheets or the Consolidated Statements of Cash Flows.

This Amendment No. 3 to PG&E Corporation's and Pacific Gas and Electric Company's joint Annual Report on Form 10-K for the year ended December 31, 2002, as amended by Form 10-K/A Amendment No. 1 filed with the Securities and Exchange Commission on March 6, 2003, and Form 10-K/A Amendment No. 2 filed with the Securities and Exchange Commission on March 12, 2003, contains revised consolidated financial statements for PG&E Corporation for the year ended December 31, 2002. To reflect the revisions, this Amendment No. 3 hereby amends:

Part I, Item I. Business. Corrections have been made to the section entitled "Utility Operations".

Part II, Item 5. Market for Registrant's Common Equity and Related Stockholder Matters. References are made to the "Quarterly, Consolidated Financial Data (unaudited)" and the "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in this Form 10-K/A, Amendment No. 3.

Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. Corrections have been made to the sections entitled "Cash Flows" and "Results of Operations".

Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk. Corrections have been made to "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the "Notes to the Consolidated Financial Statements" included in this Form 10-K/A, Amendment No. 3.

Part II, Item 8. Financial Statements and Supplementary Data. Corrections have been made to Note 1 and Note 6 of the "Notes to the Consolidated Financial Statements."

Part IV, Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K (amended to file herewith Exhibit 23, Independent Auditors' Consent (Deloitte & Touche LLP), Exhibit 99.1, Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002, and Exhibit 99.2, Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002.)

PART I

ITEM 1. Business.

GENERAL

Corporate Structure and Business

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California which conducts its business through two principal subsidiaries: Pacific Gas and Electric Company, or the Utility, an operating public utility engaged principally in the business of providing electricity and natural gas distribution and transmission services throughout most of northern and central California, and PG&E National Energy Group, Inc., or PG&E NEG, a company engaged in power generation, wholesale energy marketing and trading, risk management, and natural gas transmission.

Pacific Gas and Electric Company was incorporated in California in 1905. Effective January 1, 1997, the Utility and its subsidiaries became subsidiaries of PG&E Corporation, which was incorporated in 1995. In the holding company reorganization, the Utility's outstanding common stock was converted on a share-for-share basis into PG&E Corporation common stock. The Utility's debt securities and preferred stock were unaffected and remain as outstanding securities of Pacific Gas and Electric Company. The Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the Bankruptcy Court for the Northern District of California on April 6, 2001. 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. The Utility is regulated primarily by the California Public Utilities Commission, or CPUC, and the Federal Energy Regulatory Commission, or FERC.

PG&E NEG, headquartered in Bethesda, Maryland, 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. PG&E NEG and its subsidiaries are principally located in the United States and Canada. PG&E NEG's principal subsidiaries include: PG&E Generating Company, LLC, and its subsidiaries, or PG&E Gen; PG&E Energy Trading Holdings Corporation and its subsidiaries, or PG&E ET; and PG&E Gas Transmission Corporation and its subsidiaries, or PG&E GTC, which includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries, or PG&E GTN, and North Baja Pipeline, LLC, or NBP. PG&E NEG also has other less significant subsidiaries.

The principal executive office of PG&E Corporation is located at One Market, Spear Tower, Suite 2400, San Francisco, California 94105, and its telephone number is (415) 267-7000. The principal executive office of Pacific Gas and Electric Company is located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and its telephone number is (415) 973-7000. PG&E Corporation, the Utility, and PG&E NEG each file various reports with the Securities and Exchange Commission, or the SEC. The reports that PG&E Corporation and the Utility file with the SEC are available free of charge on both PG&E Corporation's website, *www.pge-corp.com*, and the Utility's website, *www.pge.com*. PG&E NEG's reports also are available free of charge on PG&E Corporation's website, *www.pge-corp.com*.

PG&E Corporation has identified three reportable operating segments:

- Utility,
- Integrated Energy and Marketing (or the Generation Business), and
- Interstate Pipeline Operations (or the Pipeline Business)

These segments were determined based on similarities in the following characteristics: economics, products and services, types of customers, methods of distribution, regulatory environment, and how information is reported to and used by PG&E Corporation's chief operating decision makers. 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 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2002 Annual Report to Shareholders and in Note 17 of the "Notes to Consolidated Financial Statements" of the 2002 Annual Report to Shareholders, which information is incorporated by reference into this report.

As result of the sustained downturn in the power industry during 2002, PG&E NEG and its affiliates have experienced a financial downturn which caused the major credit rating agencies to downgrade PG&E NEG's and its affiliates' credit ratings to below investment grade. PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling approximately $2.5 billion, but this debt is non-recourse to PG&E NEG. PG&E NEG and these subsidiaries continue to negotiate with their lenders regarding a restructuring of this indebtedness and these commitments. During the fourth quarter of 2002, PG&E NEG and certain subsidiaries have agreed to sell or have sold certain assets, have abandoned other assets, and have significantly reduced energy trading operations. As a result of these actions, PG&E NEG has incurred pre-tax charges to earnings of approximately $3.9 billion in 2002. PG&E NEG and its subsidiaries are continuing their efforts to abandon, sell, or transfer additional assets in an ongoing effort to raise cash and reduce debt, whether through negotiation with lenders or otherwise. As a result, PG&E NEG expects to incur additional substantial charges to earnings in 2003 as it restructures its operations. In addition, if a restructuring agreement is not reached and if the lenders exercise their default remedies or if the financial commitments are not restructured, PG&E NEG and certain of its subsidiaries may be compelled to seek protection under or be forced into a proceeding under the U.S. Bankruptcy Code. PG&E Corporation does not expect that the liquidity constraints at PG&E NEG and its subsidiaries will affect the financial condition of PG&E Corporation or the Utility.

The consolidated financial statements of PG&E Corporation incorporated in this report reflect the accounts of PG&E Corporation, the Utility, PG&E NEG, and other wholly owned and controlled subsidiaries. The separate consolidated financial statements of the Utility reflect the accounts of the Utility and its wholly owned and controlled subsidiaries.

As of December 31, 2002, PG&E Corporation had approximately $34 billion in assets. Of this amount, Pacific Gas and Electric Company had $25 billion in assets. PG&E Corporation generated approximately $12 billion in operating revenues for 2002. Of this amount, the Utility generated $11 billion in operating revenues for 2002.

As of December 31, 2002, PG&E Corporation and its subsidiaries and affiliates had 21,814 employees (including 19,575 employees of the Utility). Of the Utility's employees, approximately 13,000 are covered by collective bargaining agreements with three labor unions: the International Brotherhood of Electrical Workers, Local 1245, AFL-CIO, or IBEW; the Engineers and Scientists of California, IFPTE Local 20, AFL-CIO and CLC, or ESC; and the International Union of Security Officers/SEIU, Local 24/7, or IUSO. The collective bargaining agreements with IBEW and ESC remain in effect until the earlier of December 31, 2003 or the date on which a new agreement is completed, and the agreement with the IUSO expires on February 28, 2003. The Utility currently is in negotiations for renewal of the collective bargaining agreements with IBEW and ESC and is beginning negotiations with IUSO.

Proposed Plans of Reorganization of the Utility

The Utility will not emerge from bankruptcy until a plan of reorganization has been confirmed by the Bankruptcy Court and the confirmed plan has been implemented. A plan sets forth the means for satisfying both claims against and equity interests in a debtor.

The Utility and PG&E Corporation submitted a proposed plan of reorganization, described below as the Utility Plan. The CPUC submitted a competing proposed plan of reorganization. During the summer of 2002, holders of claims against, and equity interests in, the Utility were requested to vote whether to accept or reject the competing plans. On September 9, 2002, an independent voting agent announced that nine of the ten voting classes under the Utility Plan approved the Utility Plan. The CPUC's plan was approved by one of the eight voting classes under the CPUC's plan. In August 2002, 10 days after the voting period ended, the CPUC and the Official Committee of Unsecured Creditors, or OCC, announced that the OCC had joined the CPUC to support a modified alternative plan of reorganization. On August 30, 2002, the CPUC and the OCC jointly submitted an amended plan of reorganization to the Bankruptcy Court (the CPUC/OCC Plan).

The Bankruptcy Court began confirmation hearings in November 2002 to determine whether to confirm the Utility Plan, the CPUC/OCC Plan, or neither plan. The Bankruptcy Court currently has scheduled trial dates through March 2003.

The Utility Plan. The Utility Plan proposes to restructure the Utility's current businesses and to refinance the restructured businesses so that all allowed creditor claims would be paid in full with interest. The Utility Plan is designed to align the businesses under the regulators that best match the business functions. Assets used in the retail distribution business would remain under the retail regulator, the CPUC, and assets used in the wholesale electric generation and transmission, and interstate natural gas transportation, would be placed under wholesale regulators, the FERC and the Nuclear Regulatory Commission, or NRC. After this alignment, the retail-focused, state-regulated business would be a natural gas and electricity distribution company, the Reorganized Utility, representing approximately 70% of the book value of the Utility's assets. The Utility would retain four small generating facilities. The wholesale businesses, electric transmission, interstate gas transmission, and generation, would be federally regulated as to price, terms, and conditions of service.

In contemplation of the Utility Plan becoming effective, the Utility has created three new limited liability companies, the LLCs, which currently are owned by the Utility's wholly owned subsidiary, Newco Energy Corporation, or Newco. On the effective date of the Utility Plan, the Utility would transfer

- substantially all the assets and liabilities primarily related to the Utility's electricity generation business to Electric Generation LLC, or Gen;
- the assets and liabilities primarily related to the Utility's electricity transmission business to ETrans LLC, or ETrans; and
- the assets and liabilities primarily related to the Utility's natural gas transportation and storage business to GTrans LLC, or GTrans.

The Utility also would enter into agreements under which the Utility, Gen, ETrans and GTrans would allocate responsibility and indemnification for liabilities that survive the bankruptcy.

Although the Utility would be legally separated from the LLCs, the Utility's operations would remain connected to the operations of the LLCs after the effective date of the Utility Plan. For example

- the Utility would rely on Gen for a significant portion of the electricity the Utility needed to meet its electricity distribution customers' demand during the 12-year term of a power purchase

and sale agreement between the Utility and Gen, or the Gen power purchase and sale agreement.

- The Utility would rely on ETrans for the Utility's electricity transmission needs because the transmission lines proposed to be transferred to ETrans are currently the only transmission lines directly connected to the Utility's electricity distribution system.
- The Utility would rely on GTrans for the Utility's natural gas transportation needs because the facilities proposed to be transferred to GTrans are currently the only transportation facilities directly connected to the Utility's natural gas distribution system. In addition, the Utility would rely on GTrans for a substantial portion of the Utility's natural gas storage requirements for at least 10 years under a transportation and storage services agreement between the Utility and GTrans, though the Utility does have storage options with third party providers to meet a portion of their requirements.
- The Utility also would have significant operating relationships with the LLCs covering a range of functions and services.
- Finally, the Utility would continue to rely on its natural gas transportation agreement with PG&E Gas Transmission Northwest Corporation, or PG&E GTN, for the transportation of western Canadian natural gas.

The Utility Plan also proposes that on the effective date of the Utility Plan the Utility would distribute to PG&E Corporation 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, on the effective date of the Utility Plan or as promptly thereafter as practicable, PG&E Corporation would distribute all the shares of the Utility's common stock that it then holds to its existing shareholders in a spin-off transaction. After the spin off, the Utility would be an independent publicly held company. The Utility would retain the name "Pacific Gas and Electric Company."

Allowed claims would be satisfied by cash, long-term notes issued by the LLCs or a combination of cash and such notes. Each of ETrans, GTrans, and Gen would issue long-term notes to the reorganized Utility and the Utility will then transfer the notes to certain holders of allowed claims. In addition, each of the reorganized Utility, ETrans, GTrans, and Gen would issue "new money" notes in registered public offerings. The LLCs would transfer the proceeds of the sale of the new money notes, less working capital reserves, to the Utility for payment of allowed claims. The Utility Plan currently also would reinstate nearly $1.59 billion of preferred stock and pollution control loan agreements.

On February 19, 2003, Standard & Poor's (S&P), a major credit rating agency, announced that it had re-affirmed its preliminary rating evaluation, originally issued in January 2002, of the corporate credit ratings of, and the securities proposed to be issued by, the reorganized Utility and the LLCs in connection with the implementation of the Utility Plan. Subject to the satisfaction of various conditions, S&P stated that the approximately $8.5 billion of securities proposed to be issued by the reorganized Utility and the LLCs, as well as their corporate credit ratings, would be capable of achieving investment grade ratings of at least BBB-. In order to satisfy some of the conditions specified by S&P, on February 24, 2003, the Utility filed amendments to the Utility Plan with the Bankruptcy Court that, among other modifications:

- permit the reorganized Utility and the LLCs to issue secured debt instead of unsecured debt,

- permit adjustments in the amount of debt the reorganized Utility and the LLCs would issue so that additional new money notes could be issued if additional cash is required to satisfy allowed claims or to deposit in escrow for disputed claims and such debt can be issued while maintaining investment grade ratings, or so that less debt could be issued in order to obtain investment

grade ratings or if less cash is required to satisfy allowed claims and be deposited into escrow for disputed claims,

- require Gen to establish a debt service reserve account and an operating reserve account,

- under certain circumstances, permit an increase in the amount of cash creditors receiving cash and notes will receive,

- permit the Utility's mortgage-backed pollution control bonds to be redeemed if the reorganized Utility issues secured new money notes, and

- commit PG&E Corporation to contribute up to $700 million in cash to the Utility's capital from the issuance of equity or from other available sources, to the extent necessary to satisfy the cash obligations of the Utility in respect of allowed claims and required deposits into escrow for disputed claims, or to obtain investment grade ratings for the debt to be issued by the reorganized Utility and the LLCs.

In addition to the amendments to the Plan, amendments to various filings at the FERC, and possibly other regulatory agencies, will be required in order to implement the changes to the Plan.

The CPUC/OCC Plan. The CPUC/OCC Plan does not call for realignment of the Utility's businesses, but instead provides for the continued regulation of all of the Utility's current operations by the CPUC. The CPUC/OCC Plan proposes to reinstate nearly $1 billion of preferred stock and pollution control bonds and satisfy remaining creditor claims in full in cash, using a combination of cash on hand and the proceeds of the issuance of $7.3 billion of new senior secured debt, $1.5 billion of unsecured notes and preferred securities. The CPUC/OCC Plan proposes to establish a $1.75 billion regulatory asset that would be amortized over 10 years and would earn the full rate of return on rate base.

The CPUC/OCC Plan also provides that it would not become effective until the Utility and the CPUC enter into a "reorganization agreement" under which the CPUC promises it would establish retail electric rates on an ongoing basis sufficient for the Utility to achieve and maintain investment grade credit ratings and to recover in rates (1) the interest and dividends payable on, and the amortization and redemption of, the securities to be issued under the CPUC/OCC Plan, and (2) certain recoverable costs (defined as the amounts that the Utility is authorized by the CPUC to recover in retail electric rates in accordance with historic practice for all of its prudently incurred costs, including capital investment in property, plant and equipment, a return of capital and a return on capital and equity to be determined by the CPUC from time to time in accordance with its past practices).

PG&E Corporation and the Utility believe the CPUC/OCC Plan is not credible or confirmable. PG&E Corporation and the Utility do not believe the CPUC/OCC Plan would restore the Utility to investment grade status if it were to become effective. Additionally, PG&E Corporation and the Utility believe the CPUC/OCC Plan would violate applicable federal and state law.

Risk Factors

This report includes forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current expectations and 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," "could," "should," "would," "may," 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 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:

Recovery of Undercollected Power Procurement and Transition Costs Previously Written Off. The extent to which the Utility is able to recover its undercollected power procurement and transition costs previously written off depends on many factors, including:

- what costs the CPUC determines are eligible for recovery as transition costs;
- when the Utility's rate freeze ended, as determined by the CPUC;
- sales volatility and the level of direct access customers (i.e., those customers who choose an alternative energy provider);
- changes in the California Department of Water Resources' (DWR) revenue requirements required to be remitted to the DWR from existing retail rates;
- changes in the Utility's authorized revenue requirements;
- future regulatory or judicial decisions that determine whether the Utility is allowed under state law to recover undercollected power procurement and transition costs from its customers after the end of the rate freeze; and
- the outcome of the Utility's claims against the CPUC Commissioners for recovery of undercollected power procurement and transition costs based on the federal filed rate doctrine.

Refundability of Amounts Previously Collected. Whether the Utility is required to refund to ratepayers amounts previously collected depends on many factors, including:

whether the CPUC determines that certain transition or procurement costs recovered in revenues collected by the Utility were not eligible transition costs or otherwise reduces the amount of revenues authorized to recover such transition or procurement costs due to an overcollection of such costs;

whether the CPUC ultimately determines that certain past power procurement costs incurred by the Utility were not reasonably incurred and should be disallowed; and

the purposes for which the CPUC ultimately determines that surcharges approved by the CPUC in January, March, and May 2001 may be used.

Outcome of the Utility's Bankruptcy Case. The pace and outcome of the Utility's bankruptcy case will be affected by:

whether the Bankruptcy Court confirms the Utility Plan, the CPUC/OCC Plan, or some other plan of reorganization;

whether regulatory and governmental approvals required to implement a confirmed plan are obtained and the timing of such approvals;

whether there are any delays in implementation of a plan due to litigation related to regulatory, governmental, or Bankruptcy Court orders; and

future equity or debt market conditions, future interest rates, future credit ratings, and other factors that may affect the ability to implement either plan or affect the amount and value of the securities proposed to be issued under either plan.

Utility's Operating Environment. The amount of operating income and cash flows that the Utility may record may be influenced by the following:

future regulatory actions regarding the Utility's procurement of power for its retail customers;

the terms and conditions of the Utility's long-term generation procurement plan as approved by the CPUC;

the ability of the Utility to timely recover in full its costs including its procurement costs;

future sales levels, which can be affected by general economic and financial market conditions, changes in interest rates, weather, conservation efforts, outages, and the level of direct access customers (i.e., those customers who choose an alternative energy provider);

the demand for and pricing of transportation and storage services which may be affected by weather, overall gas-fired generation, and price spreads between various natural gas delivery points;

changes in the Utility's authorized revenue requirements; and

acts of terrorism, storms, earthquakes, accidents, mechanical breakdowns, or other events or perils that result in power outages or damage to the Utility's assets or operations, to the extent not covered by insurance.

Legislative and Regulatory Environment. PG&E Corporation's, the Utility's, and PG&E NEG's businesses may be impacted by legislative or regulatory changes affecting the electric and natural gas industries in the United States.

Regulatory Proceedings and Investigations. PG&E Corporation's and the Utility's business may be affected by:

- the outcome of the Utility's various regulatory proceedings pending at the CPUC and at the FERC, and
- the outcome of the CPUC's pending investigation into whether the California investor-owned utilities, or IOUs, have complied with past CPUC decisions, rules, or orders authorizing their holding company formations and/or governing affiliate transactions, as well as applicable statutes.

Pending Legal Proceedings. PG&E Corporation's and the Utility's future results of operations and financial condition may be affected by the outcomes of:

- the lawsuits filed by the California Attorney General and the City and County of San Francisco 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;
- 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
- other pending litigation.

Competition. PG&E Corporation's and the Utility's future results of operations and financial condition may be affected by:

- the threat of municipalization which may result in stranded Utility investment, loss of customer growth, and additional barriers to cost recovery;
- changes in the level of direct access customer cost responsibility and other surcharges related to direct access, and competition from other service providers to the extent restrictions on direct access are removed;
- the development of alternative energy technologies;
- the ability to compete for gas transmission services into Southern California and with alternative storage providers throughout California; and

- the growth of distributed generation or self-generation.

Environmental and Nuclear Matters. PG&E Corporation's and the Utility's future results of operations and financial condition may be affected by:

- the effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant;

- the outcome of pending environmental matters or proceedings;
- whether the Utility is able to fully recover in rates the costs of complying with existing and future environmental laws, regulations, and policies, the cost of which could be significant; and
- whether the Utility incurs costs in connection with its nuclear facilities that exceed the Utility's insurance coverage and other amounts set aside for decommissioning and other potential liabilities.

Accounting and Risk Management. PG&E Corporation's and the Utility's future results of operations and financial condition may be affected by:

- the effect of new accounting pronouncements;
- changes in critical accounting estimates;
- volatility in income resulting from mark-to-market accounting and changes in mark-to-market methodologies;
- the extent to which the assumptions underlying critical accounting estimates, mark-to-market accounting, and risk management programs are not realized;
- the volatility of commodity fuel and electricity prices, and the effectiveness of risk management policies and procedures designed to address volatility; and
- the ability of counterparties to satisfy their financial commitments and the impact of counterparties' nonperformance on PG&E NEG's liquidity.

Efforts to Restructure PG&E NEG's Indebtedness. Whether PG&E NEG and certain of its subsidiaries seek protection under or be forced into a proceeding under the U.S. Bankruptcy Code will be affected by:

- the outcome of PG&E NEG's negotiations with lenders under various credit facilities as well as with representatives of the holders of PG&E NEG's Senior Notes to restructure PG&E NEG's and its subsidiaries' indebtedness and commitments;
- the terms and conditions of any sale, transfer, or abandonment of certain of PG&E NEG's merchant assets, including its New England generating assets, that PG&E NEG may enter into; and
- the terms and conditions under which certain generating projects will be transferred to the project lenders as required by recent restructuring agreements.

PG&E NEG Operational Risks. PG&E Corporation's future results of operations and financial condition will be affected by:

- the extent to which PG&E NEG incurs further charges to earnings as a result of the abandonment, sale or transfer of assets, or termination of contractual commitments, whether such transactions occur in connection with restructuring of PG&E NEG's indebtedness or otherwise;

any potential charges to income that would result from the reduction and potential discontinuance of energy trading and marketing operations, including tolling transactions;

any potential charges to income that would result from the discontinuance or transfer of any of PG&E NEG's merchant generation assets;

the inability of PG&E NEG, its merchant asset and other subsidiaries, including USGen New England, Inc., to maintain sufficient liquidity necessary to meet their commodity and other obligations;

the extent to which PG&E NEG's current construction of generation, pipeline, and storage facilities is completed and the pace and cost of that completion, including the extent to which commercial operations of these construction projects are delayed or prevented because of financial or liquidity constraints, changes in the national energy markets and by the extent and timing of generating, pipeline, and storage capacity expansion and retirements by others; or by 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 and the potential loss of permits or other rights in connection with PG&E NEG's decision to delay or defer construction;

the impact of layoffs and loss of personnel; and

future sales levels which can be affected by economic conditions, weather, conservation efforts, outages, and other factors.

Current Conditions in the Energy Markets and the Economy. PG&E Corporation's future results of operations and financial condition will be affected by changes in the energy markets, changes in the general economy, wars, embargoes, financial markets, interest rates, other industry participant failures, the markets' perception of energy merchants and other factors.

Actions of PG&E NEG Counterparties. PG&E Corporation's future results of operations and financial condition may be affected by:

The extent to which counterparties demand additional collateral in connection with PG&E ET's trading and nontrading activities and the ability of PG&E NEG and its subsidiaries to meet the liquidity calls that may be made; and

The extent to which counterparties seek to terminate tolling agreements and the amount of any termination damages they may seek to recover from PG&E NEG as guarantor.

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.

REGULATION

Various aspects of PG&E Corporation's and its subsidiaries' businesses, including the Utility, are subject to a complex set of energy, environmental, and other governmental laws and regulations at the federal, state and local levels. This section summarizes some of the more significant laws and regulations affecting PG&E Corporation's business at this time.

Regulation of PG&E Corporation

PG&E Corporation and its subsidiaries are exempt from all provisions, except Section 9(a)(2), of the Public Utility Holding Company Act of 1935, or the Holding Company Act. At present, PG&E Corporation has no expectation of becoming a registered holding company under the Holding Company Act. On July 7, 2001, the California Attorney General, or the AG, filed a petition with the

SEC requesting the SEC to review and revoke PG&E Corporation's exemption from the Holding Company Act and to begin fully regulating the activities of PG&E Corporation and its affiliates. The AG's petition requested the SEC to hold a hearing on the matter as soon as possible, and requested a response from the SEC no later than September 5, 2001. On August 7, 2001, PG&E Corporation responded in detail to the AG's petition demonstrating that PG&E Corporation met the SEC's criteria for the intrastate exemption. On October 4, 2001, the AG filed a "supplement" to its petition requesting that the SEC consider additional issues and to set the matter for hearing. PG&E Corporation responded to the supplement on October 30, 2001, and once again demonstrated that there was no basis for action by the SEC. In comments filed on November 14, 2002 on PG&E Corporation's 9(a)(2) filing made with the SEC in connection with the implementation of the Utility Plan, the AG reiterated the arguments made in its July 7, 2001 and October 4, 2001 filings with the SEC. In its response filed with the SEC on January 24, 2003, PG&E Corporation responded to those arguments and demonstrated that there was no basis for SEC action with respect to those issues. To date, the SEC has neither instituted an investigation nor ordered hearings regarding the matters raised in the AG's petition.

PG&E Corporation is not a public utility under the laws of California and is not subject to regulation as such by the CPUC. However, the CPUC approval authorizing Pacific Gas and Electric Company to form a holding company was granted subject to various conditions related to finance, human resources, records and bookkeeping, and the transfer of customer information. As further discussed below, in January 2002, the CPUC issued a decision asserting that it maintains jurisdiction to enforce the conditions against PG&E Corporation and similar holding companies and to modify, clarify or add to the conditions. The financial conditions provide that

- the Utility is precluded from guaranteeing any obligations of PG&E Corporation without prior written consent from the CPUC,
- the Utility's dividend policy must continue to be established by the Utility's Board of Directors as though Pacific Gas and Electric Company were a stand-alone utility company,
- the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, must be given first priority by PG&E Corporation's Board of Directors (the "first priority condition"), and
- the Utility must maintain on average its CPUC-authorized utility capital structure, although it shall have an opportunity to request a waiver of this condition if an adverse financial event reduces the Utility's equity ratio by 1% or more.

The CPUC also has adopted complex and detailed rules governing transactions between California's natural gas local distribution and electric utility companies and their non-regulated affiliates. The rules permit non-regulated affiliates of regulated utilities to compete in the affiliated utility's service territory, and also to use the name and logo of their affiliated utility, provided that in California the affiliate includes certain designated disclaimer language which emphasizes the separateness of the entities and that the affiliate is not regulated by the CPUC. The rules also address the separation of regulated utilities and their non-regulated affiliates and information exchange among the affiliates. The rules prohibit the utilities from engaging in certain practices that would discriminate against energy service providers that compete with the utility's non-regulated affiliates. The CPUC also has established specific penalties and enforcement procedures for affiliate rules violations. Utilities are required to self-report affiliate rules violations.

On April 3, 2001, the CPUC issued an order instituting an investigation into whether the California IOUs, 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, 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' actions 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. PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules, and orders.

On January 9, 2002, the CPUC issued two decisions in its pending investigation. In one decision, the CPUC, for the first time, adopted a broad interpretation of the first priority condition and 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 three major California IOUs and their parent holding companies had opposed this broader interpretation as being inconsistent with the prior 15 years' understanding of that condition as applying more narrowly to a priority on capital needed for investment purposes. 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 the other 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. The CPUC stated that PG&E Corporation was being dismissed so that an appropriate legal forum; i.e., the state court action discussed below, could decide expeditiously whether adoption of the Utility's proposed plan of reorganization would violate the first priority condition.

On January 10, 2002, the AG 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, based on allegations of unfair or fraudulent business acts or practices in violation of California Business and Professions Code Section 17200. Among other allegations, the AG alleges that PG&E Corporation violated the various conditions established by the CPUC in decisions approving the holding company formation. After the AG's complaint was filed, two other complaints containing substantially similar allegations were filed by the City and County of San Francisco and by a private plaintiff. For more information, see "Item 3 Legal Proceedings" below.

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 can predict what the outcomes of the CPUC's investigation, the AG's petition to the SEC, and the related litigation will be or whether the outcomes will have a material adverse effect on their results of operations or financial condition.

Regulation of Pacific Gas and Electric Company

Federal Regulation

The FERC. The FERC is an independent agency within the U.S. Department of Energy, or the DOE. The FERC regulates the interstate sale and transportation of natural gas, the transmission of electricity in interstate commerce and the sale for resale of electricity in interstate commerce. The FERC regulates electric transmission rates and access, interconnections, operation of the California Independent System Operator, or ISO, and the terms and rates of wholesale electric power sales. The ISO has responsibility for providing open access transmission service on a non-discriminatory basis, meeting applicable reliability criteria, planning transmission system additions, and assuring the maintenance of adequate reserves and is subject to FERC regulation of tariffs and conditions of service. In addition, the FERC has jurisdiction over the Utility's electric transmission revenue requirements and rates. Further, most of the Utility's hydroelectric facilities are subject to licenses issued by the FERC.

In an effort to support the development of competitive markets, the FERC announced in its Order 2000 a policy of promoting regional transmission organizations, or RTOs, which would perform specified functions similar to the ISO. Under the FERC's Order 2000, RTOs would generally span areas where multiple utilities may have operated in the past in order to enhance the efficiency of power markets, for example, by eliminating duplicative charges from one transmission system to the next in a region. Order 2000 encourages utilities owning transmission systems to form RTOs on a voluntary basis. The Utility is a participant in the ISO; however, the FERC has not yet approved the ISO's status as a RTO under Order 2000.

In the FERC's proposal for a standard market design, the FERC has proposed additional changes to the open access transmission tariff initially established under the FERC's Order 888 to standardize transmission service and wholesale electric market design to address undue discrimination in interstate transmission services. The FERC has proposed that all public utilities with open access transmission tariffs file modifications to their tariffs to conform to the FERC's standard. These proposed changes would require all independent transmission providers or RTOs to participate in a regional planning process for grid upgrades and expansion to ensure grid reliability. The FERC proposed approving participant funding of certain new facilities, meaning those who would directly benefit from those facilities would be required to pay for them. PG&E Corporation filed comments on November 15, 2002 supporting the goals of the FERC's proposal, and is continuing to participate in the rulemaking process as it moves forward.

The ISO issued its own Comprehensive Market Design Proposal to effect changes to the structure and operation of the California electricity market. Implementation of the first phase of the proposal, automated market mitigation procedures, occurred in the fourth quarter of 2002, with subsequent phases to address real-time economic dispatch, integrated forward markets, locational marginal pricing, and congestion management scheduled to occur in 2003 and 2004.

In a separate proceeding, the FERC has proposed that all transmission providers use standard interconnection procedures and a standard agreement for generator interconnections. The generator interconnection rules, if adopted as proposed, would require the Utility to update and construct additional facilities based on decisions by new generators, and would preclude the Utility from disclaiming consequential damages for any claims or limiting the Utility's liability for its negligence in any new generator interconnection agreements. The FERC has also held that transmission providers, like the Utility, must upgrade existing facilities or construct new facilities to interconnect with new generators, and that while generators will generally be responsible for initially funding the costs of such facilities, some of which costs over time must be refunded by the Utility and recovered in the Utility's rates. The FERC recently held that generators are entitled to a credit for the cost of network upgrades

which they funded even if the FERC previously had accepted agreements which directly assigned to the generators responsibility for the cost of those upgrades.

In response to the unprecedented increase in wholesale electricity prices, the FERC issued a series of orders in the spring and summer of 2001 and July 2002 aimed at mitigating future extreme wholesale energy prices like those in 2000 and 2001. These orders established a cap on bids for real-time electricity and ancillary services of $250/MWh and established various automatic mitigation procedures. Recently, in the FERC's standard market design proposed rules, the FERC proposed to adopt a safety net bid cap as part of the mitigation plan for wholesale energy markets and has requested comments on the appropriate value for such a bid cap.

Also, in June and July 2001, the FERC's chief administrative law judge conducted settlement negotiations among power sellers, the State of California and the California IOUs in an attempt to resolve disputes regarding past power sales. The negotiations did not result in a settlement, but the judge recommended that the FERC conduct further hearings to determine possible refunds and what the power sellers and buyers are each owed. The FERC has asserted that it would not order refunds for periods before October 2, 2000, because under a federal statute it can only consider ordering refunds as far back as 60 days after a complaint for overcharges was filed. The first complaint for overcharges was filed with the FERC in August 2000. These hearings, in which various parties, including the Utility and the State of California, which is seeking up to $8.9 billion in refunds for electricity overcharges on behalf of buyers, including the Utility, were concluded in October 2002. However, an August 21, 2002, order from the U. S. Court of Appeals for the Ninth Circuit ordered the FERC to allow the California parties "to adduce additional evidence of market manipulation by various sellers...." In November 2002, the FERC gave parties until February 28, 2003 to submit more evidence and conduct fact-finding on whether California's energy market was manipulated. On December 17, 2002, a FERC administrative law judge issued a ruling permitting the California parties to conduct discovery of potential market manipulation affecting California ISO and PX markets within all 14 western states and parts of Canada comprising the Western Electricity Coordinating Council to support claims for refunds. The judge also ruled new evidence is admissible on market manipulation and artificially inflated prices for natural gas, the chief fuel used to generate electricity.

On December 12, 2002, a FERC administrative law judge issued an initial decision finding that power companies overcharged the utilities, the State of California and other buyers from October 2, 2000 to June 2001 by $1.8 billion, but that California buyers still owe the power companies $3 billion, leaving $1.2 billion in unpaid bills. The time period reviewed in the FERC hearings excludes the claims for refunds for overcharges that occurred before October 2, 2000 and after June 2001 when the DWR entered into contracts to buy power.

After the final round of evidence-gathering ends, the FERC commissioners must decide whether to uphold or change the initial decision. It is uncertain when the FERC will issue a decision.

The NRC. The NRC oversees the licensing, construction, operation, and decommissioning of nuclear facilities, including the Diablo Canyon Nuclear Power Plant (Diablo Canyon) and the retired nuclear generating unit at Humboldt Bay Unit 3. NRC regulations require extensive monitoring and review of the safety, radiological, environmental and security aspects of these facilities.

State Regulation

The CPUC. The CPUC has jurisdiction to set retail rates and conditions of service for the Utility's electric distribution, gas distribution, and gas transmission services in California. The CPUC also has jurisdiction over the Utility's sales of securities, dispositions of utility property, energy procurement on behalf of its electric and gas retail customers, rate of return, rates of depreciation, and certain aspects of the Utility's siting and operation of its electric and gas transmission and distribution systems. Ratemaking for retail sales from the Utility's remaining generation facilities is under the

jurisdiction of the CPUC. To the extent such power is sold for resale into wholesale markets, however, it is under the ratemaking jurisdiction of the FERC. The CPUC also conducts various reviews of utility performance and conducts investigations into various matters, such as deregulation, competition, and the environment, in order to determine its future policies. The CPUC consists of five members appointed by the Governor of California and confirmed by the California State Senate for six-year terms.

The CEC. The California Energy Resources Conservation and Development Commission, also called the California Energy Commission, or the CEC, makes electricity-demand forecasts for the state and for specific service territories. Based upon these forecasts, the CEC determines additional energy sources and conservation program needs. The CEC has jurisdiction over the siting and construction of new thermal electric generating facilities 50 MW and greater in size. The CEC sponsors alternative-energy research and development projects, promotes energy conservation programs, and maintains a statewide plan of action in case of energy shortages. In addition, the CEC certifies power plant sites and related facilities within California. The CEC also administers funding for public purpose research and development, and renewable technologies programs.

California Legislature. The California Legislature also has an active role in the regulation of California IOUs. Over the last several years, the Utility's operations have been significantly affected by statutes passed by the California Legislature.

Assembly Bill 1890 California Electric Industry Restructuring. In 1998, California implemented Assembly Bill 1890, or AB 1890, which mandated the restructuring of the California electric industry 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 CPUC also issued many decisions to implement electric industry restructuring. Electric industry restructuring included the following components:

The Rate Freeze and Transition Cost Recovery Beginning January 1, 1997, electric rates for all customers were frozen at the level in effect on June 10, 1996, except that on January 1, 1998, rates for residential and small commercial customers were reduced by a further 10% and frozen at that level. The rate freeze for each IOU was supposed to end when that IOU had recovered its eligible "transition" costs (costs of utility generation-related assets and obligations that were expected to become uneconomic under the new competitive generation market structure), but not later than March 31, 2002. Under limited circumstances, some transition costs could be recovered after the transition period. Costs eligible for recovery as transition costs, as determined by the CPUC, include (1) above-market sunk costs associated with utility generating facilities that are fixed and unavoidable and that were included in customer rates on December 20, 1995, and future unavoidable above-market firm obligations, such as costs related to plant removal, (2) costs associated with pre-existing long-term contracts to purchase power at then above-market prices from qualifying facilities, or QFs, and other power suppliers, and (3) generation-related regulatory assets and obligations. Frozen rates were designed to recover authorized utility costs and, to the extent the frozen rates generated revenues in excess of authorized utility costs, recover the Utility's transition costs. Transition costs also were to be recovered by other revenue sources including (1) the portion of the market value of generation assets sold by the Utility or market valued by the CPUC that is in excess of book value, (2) revenues from energy sales from the utilities' remaining electric generation facilities that exceeded the allowed revenue requirements for the utilities' costs to generate or obtain such electricity, and (3) revenues provided after the end of the transition period for rate reduction bond principal repayments to recover deferred transition costs associated with the financed 10% rate reduction and issuance of the rate reduction bonds to finance such reduction.

For the first two years of the transition period, the revenues from frozen retail rates exceeded the generation costs included in retail rates. Based on the resulting net revenues and other revenue sources

used to recover transition costs, it appeared that the Utility's transition costs would be recovered before March 31, 2002, thus allowing the rate freeze to end sooner than the statutory end date. Although the Utility informed the CPUC in late 2000 that it had satisfied the statutory conditions for ending the rate freeze by no later than August 31, 2000, the CPUC adopted changes to its regulatory accounting rules in March 2001 that had the effect of changing the classification of costs recovered in the Utility's regulatory balancing accounts and reversing the

Utility's prior collection of transition costs.

In June 2000, wholesale electricity prices began to increase and reached unprecedented levels in November 2000 and later months. During the California energy crisis, frozen rates were insufficient to cover the Utility's electricity procurement and other costs. By December 31, 2000, the Utility had accumulated approximately $6.9 billion in undercollected purchased power and transition costs that the CPUC would not allow the Utility to collect from its customers. Because the Utility could no longer conclude that such costs were probable of recovery, the Utility charged this $6.9 billion to earnings during 2000.

In the first quarter of 2001, the CPUC authorized the Utility to begin collecting energy surcharges totaling $0.04 per kWh (composed of a $0.01 per kWh surcharge in January and a $0.03 per kWh surcharge approved in March). Although the CPUC authorized the $0.03 per kWh surcharge in March 2001, the Utility did not begin collecting the revenues until June 2001. As a result, in May 2001, the CPUC authorized the Utility to collect an additional $0.005 per kWh surcharge revenue for 12 months to make up for the time lag in collection of the $0.03 surcharge revenues. Although the collection of this "half-cent surcharge" was originally scheduled to end on May 31, 2002, the CPUC issued a resolution ordering the Utility to continue collecting the half-cent surcharge until further consideration by the CPUC. The CPUC restricted the use of these surcharge revenues to pay for the Utility's "ongoing procurement costs" and "future power purchases." Due to these surcharges, the Utility has been collecting revenues in excess of its ongoing costs of utility service enabling the Utility to partially recover its undercollected power procurement and transition costs previously written off. The amount of undercollected power procurement and transition costs has been reduced to approximately $2.2 billion (after-tax) at December 31, 2002.

In November 2002, the CPUC approved a decision modifying the restrictions on the use of revenues generated by the surcharges to permit the revenues to be used for the purpose of securing or restoring the Utility's reasonable financial health, as determined by the CPUC. The CPUC will determine in other proceedings how the surcharge revenues can be used, whether there is any cost or other basis to support specific surcharge levels, and whether the resulting rates are just and reasonable. After the CPUC determines when the AB 1890 rate freeze ended (which the CPUC states ended no later than March 31, 2002), the CPUC will determine the extent and disposition of the Utility's undercollected costs, if any, remaining at the end of the rate freeze. If the CPUC determines that the Utility recovered revenues in excess of its transition costs or in excess of other permitted uses, the CPUC may require the Utility to refund such excess revenues.

In a case currently pending before it relating to the CPUC's settlement with Southern California Edison, the Supreme Court of California is considering whether the CPUC has the authority to enter into a settlement which allows Southern California Edison to recover undercollected procurement and transition costs in light of the provisions of AB 1890. The Utility cannot predict the outcome of this case or whether the CPUC or others would attempt to apply any ruling to the Utility. If the Utility is ordered to refund material amounts to ratepayers the Utility's financial condition and results of operations would be materially adversely affected.

Direct Access AB 1890 gave the Utility's customers the choice of continuing to buy electricity from the California IOUs or buying electricity from independent power generators or retail electricity suppliers beginning April 1, 1998. Customers who choose to buy their electricity from independent power generators or retail electricity suppliers are called direct access customers. Most of the Utility's customers continued to buy electricity through 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, preventing additional customers from entering into contracts to purchase electricity from alternative energy providers. In a subsequent decision issued on March 21, 2002, the CPUC decided to allow all customers with direct access contracts entered into on or before September 20, 2001 to remain on direct access. The CPUC has established an exit fee, or non-bypassable charge, on those direct access customers to avoid a shift of costs from direct access customers to bundled service customers. For more information, see "Electric Ratemaking Electric Procurement Direct Access" below.

The Power Exchange, the Independent System Operator, and the Buy/Sell Requirement AB 1890 called for the creation of the California Power Exchange, or the PX. The PX provided an auction process, intended to be competitive, to establish hourly transparent market clearing prices for electricity in the markets operated by the PX. The PX operated the following energy markets:

- the day-ahead market where market participants purchased power for their customers' needs for the following day,
- the day-of market where market participants purchased power needed to serve their customers on the same day, and
- the block forward market, or BFM, that matched bids to buy a specific amount of power for one month (and later one-quarter and annual terms) with offers to sell power for the same period in advance of the contracted delivery date.

This short-term spot market approach represented a dramatic shift from the existing pricing approach based on a portfolio of short and longer-term contracts. At the time the PX was formed and in several subsequent decisions, the CPUC ruled that prices paid by utilities to the PX under the CPUC's "buy-sell" mandate were presumed to be prudent and reasonable for the purpose of recovery in retail rates.

AB 1890 also called for the creation of the ISO to exercise centralized operational control of the statewide transmission grid. The California IOUs were obligated to transfer control, but not ownership, of their transmission systems to the ISO. The ISO is responsible for ensuring the reliability of the

transmission grid and keeping momentary supply and demand in balance. The PX market was augmented by a spot "real-time" market maintained by the ISO. If enough power was not purchased and scheduled to meet the actual real-time demands for power being placed on the transmission system, then the ISO was authorized under its FERC-approved tariffs to purchase and provide the electricity from any other sources within or outside of California, often at high rates, to make up the difference in order to keep the electrical grid operating reliably. The ISO billed the PX for such power deficiencies, and the PX in turn billed the IOUs to the extent the IOUs were unable to purchase sufficient supply from the PX for their retail customers.

The PX's BFM provided the Utility a limited opportunity to hedge against prices in the PX day-ahead market only; it did not enable the Utility to hedge against ISO real-time market prices. In July 1999, the Utility obtained CPUC authority to participate in the BFM and the Utility subsequently entered into several BFM contracts.

Due to the January 2001 downgrades in the Utility's credit ratings and the Utility's alleged failure to post collateral for all market transactions, the PX suspended the Utility's market trading privileges as of January 19, 2001. Further, the PX sought to liquidate the Utility's BFM contracts for the purchase of power. On February 5, 2001, the Governor, acting under California's Emergency Services Act, seized the Utility's BFM contracts for the benefit of the State. Under the Act, the State must pay the Utility the reasonable value of the contracts, although the PX may seek to recover monies that the Utility owes to the PX from any proceeds realized from those contracts. The Utility subsequently filed a complaint against the State to recover the value of the seized contracts. This litigation is still pending.

Divestiture and Market Valuation of Generation Assets The structure of the transition to a fully competitive generation market established by AB 1890 also required all of the Utility's generation assets to be market valued, if not through sale, then through appraisal or other divestiture. Under AB 1890, the CPUC was required to complete market valuation of all generation assets by December 31, 2001. Under AB 1890, once an asset had been market valued, it was no longer subject to rate regulation by the CPUC. The market valuation process was intended to be an integral and essential step in recovering transition costs and measuring whether the transition period had ended. The transition costs eligible for recovery were to be calculated by netting above-market assets against below-market assets. Once market valuation had occurred, the end of the rate freeze date was to be computed retroactively to the point at which all transition costs had been recovered. To date, the only assets of the Utility that the CPUC has valued have been those that were divested through sale, except with respect to the Utility's Hunters Point power plant, which the CPUC ruled had no market value. The Utility timely submitted proposed market valuations of retained generation facilities, so that those facilities could be valued by the CPUC and no longer subject to CPUC regulation. In August 2000, the Utility submitted an interim market valuation of $2.8 billion for its hydroelectric generation facilities. Additionally, in June and December 2000, the Utility submitted testimony to the CPUC providing a market valuation of its hydroelectric facilities of $4.1 billion.

In 1995, in anticipation of the transition to a competitive wholesale electric market, the CPUC ordered the California IOUs to file plans to divest at least 50% of their fossil fuel-fired generation assets. Moreover, as an incentive to sell the remainder of the Utility's generation assets, the CPUC reduced the return on equity that the Utility could earn on any retained generation asset substantially below its otherwise authorized return to a level equivalent to 90% of the Utility's embedded cost of debt (or 6.77%). The Utility sold virtually all of its fossil-fuel fired and geothermal generation capacity with CPUC authorization and approval. By January 2000, the Utility owned only its large nuclear power generating facility at Diablo Canyon, its hydroelectric generation facilities, and two smaller, older fossil facilities. As the amount of the Utility's own generation resources decreased, the Utility was forced to rely on power supplied by third-party power producers through the PX to meet the electricity demands of its customers.

Assembly Bill 1X California Department of Water Resources. In late December 2000 and early January 2001, the Utility's creditworthiness deteriorated and it was no longer able to comply with the ISO's creditworthiness criteria, spelled out in the ISO tariff, for scheduling third-party power transactions through the ISO. The Utility was unable to continue financing its wholesale power purchases in light of its downgraded credit ratings. On January 17, 2001, the Governor of California signed an order declaring an emergency and authorizing the California Department of Water Resources, or the DWR, to purchase power to maintain the continuity of supply to retail customers. On February 1, 2001, the Governor signed Assembly Bill 1X, or AB 1X, to authorize the DWR to purchase power and sell that power directly to the utilities' retail end-use customers. AB 1X also required the Utility to deliver the power purchased by the DWR over its distribution systems and to act as a billing and collection agent on behalf of the DWR, without taking title to such power or reselling it to its customers.

AB 1X allows the DWR to recover, as a revenue requirement, among other things: (1) amounts necessary to pay for the power and associated transmission and related services, (2) amounts needed to pay the principal and interest on bonds issued to finance the purchase of power, (3) administrative costs, and (4) certain other amounts associated with the program. AB 1X authorizes the CPUC to set rates to cover the DWR's revenue requirements (but prohibits the CPUC from increasing electric rates for residential customers who use less power than 130% of their existing baseline quantities).

Assembly Bill 6X Prohibition on Disposition of Retained Utility-Owned Generating Assets. In January 2001, the California legislature also enacted AB 6X, which prohibits disposition of utility-owned generating facilities before January 1, 2006. On December 21, 2001, the assigned CPUC Commissioner issued a ruling for comment in which she expressed her opinion 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 its comments on the proposal stating that AB 6X did not relieve the CPUC of its statutory obligation to market value the retained generation by December 31, 2001. The CPUC has not yet issued a decision on this matter.

On January 2, 2002, the CPUC issued a decision finding that AB 6X had materially affected the implementation of AB 1890. The CPUC scheduled further proceedings to address the impact of AB 6X on the AB 1890 rate freeze for the Utility and to determine the extent and disposition of the Utility's remaining unrecovered transition costs. In its November 2002 decision regarding the surcharge revenues, discussed above, the CPUC reiterated that it had yet to decide when the rate freeze ended and the disposition of any undercollected costs remaining at the end of the rate freeze.

On January 17, 2002, the Utility filed an administrative claim with the State of California Victim Compensation and Government Claims Board alleging that AB 6X violates the Utility's statutory rights under AB 1890. The Utility's claim seeks compensation for the denial of its right to at least $4.1 billion market value of its retained generating facilities. On March 7, 2002, the Claims Board formally denied the Utility's claim. Having exhausted remedies before the Claims Board, on September 6, 2002, the Utility filed a complaint against the State of California for breach of contract in the California Superior Court. On January 9, 2003, the Superior Court granted the State's request to dismiss the Utility's complaint, finding that AB 1890 did not constitute a contract. The Utility has 60 days to file an appeal and intends to do so.

Senate Bill 1976 Resumption of Procurement. Under AB 1X, the DWR was prohibited from entering into new electricity purchase contracts and from purchasing electricity on the spot market after December 31, 2002. In September 2002, the Governor signed California Senate Bill 1976, or SB 1976, into law. SB 1976 required the CPUC to allocate electricity subject to existing DWR contracts among the customers of the California IOUs, including the Utility's customers. Each IOU had to submit, within 60 days of the CPUC's allocation of the existing DWR contracts, a proposed electricity procurement plan to the CPUC specifying the date that the IOU intends to resume procurement of electricity for its retail customers.

As part of the resumption of the procurement function, each IOU would procure electricity for that portion of its customers' needs that is not covered by the combination of the allocation of electricity from existing DWR contracts to that IOU's customers and the IOU's own electric resources and contracts (referred to as the residual net open position).

SB 1976 requires that each procurement plan include one or more of the following features:

- A competitive procurement process under a format authorized by the CPUC, with the costs of procurement obtained in compliance with the authorized bidding format being recoverable in rates;

- A clear, achievable, and quantifiable incentive mechanism that establishes benchmarks for procurement and authorizes the IOUs to procure from the market subject to comparison with the CPUC-authorized benchmarks; and/or

Upfront and achievable standards and criteria to determine the acceptability and eligibility for rate recovery of a proposed transaction and an expedited CPUC pre-approval process for proposed bilateral contracts to ensure compliance with the individual utility's procurement plan.

The CPUC must review each procurement plan but SB 1976 provides that the CPUC may not approve a procurement plan if it finds the plan contains features or mechanisms that would impair restoration of the IOU's creditworthiness or would lead to a deterioration of the IOU's creditworthiness. A procurement plan approved by the CPUC must accomplish the following objectives, among others:

Enable the IOU to fulfill its obligation to serve its customers at just and reasonable rates;

Eliminate the need for after-the-fact reasonableness review of actions in compliance with an approved procurement plan, including resulting electricity procurement contracts and related expenses, subject to verification and assurance that each contract was administered in accordance with the terms of the contract and that contract disputes that arise are resolved reasonably; and

Moderate the price risk associated with serving its customers by authorizing the IOU to enter into financial and other electricity-related product contracts.

SB 1976 requires the CPUC to:

create electric procurement balancing accounts to track and allow recovery of the differences between recorded revenues and costs incurred under an approved procurement plan;

review the revenues and costs associated with the IOU's procurement plan at least semi-annually and adjust rates or order refunds as necessary; and

establish the schedule for amortizing the overcollections or undercollections in the electric procurement balancing accounts at least through January 1, 2006, so that the aggregate overcollection or undercollection reflected in the accounts does not exceed 5% of the IOU's actual recorded generation revenues for the prior calendar year, excluding revenues collected on behalf of the DWR.

On September 19, 2002, the CPUC issued a decision allocating electricity subject to the DWR contracts to the generation portfolios of the three California IOUs for operational and scheduling purposes, with the DWR retaining legal title and financial reporting and payment responsibilities associated with these contracts. The IOUs will, however, become responsible for scheduling and dispatch of the quantities subject to the allocated contracts and for many administrative functions associated with those contracts.

On October 24, 2002, the CPUC issued a decision establishing an accelerated schedule for submission and approval of procurement plans for each California IOU with a view to these utilities resuming procurement responsibility for their net open position on January 1, 2003. On December 19,

2002, the CPUC adopted, in large part but with modifications, the Utility's revised 2003 interim procurement plan. The CPUC also authorized the IOUs to extend their planning into the first quarter of 2004 and directed them to hedge their 2004 first quarter residual net short positions with transactions entered into in 2003. The Utility is required to submit its long-term procurement plan covering the next 20 years by April 1, 2003.

In December 2002, the CPUC determined that the maximum risk of potential disallowance each IOU should face for all of its procurement activities should be limited to twice its annual administrative costs of managing procurement activities. The Utility anticipates that its annual administrative costs of managing procurement activities will be approximately $18 million in 2003.

On January 1, 2003, the California IOUs resumed the function of procuring electricity to meet their customers' residual net open position and became responsible for the operational and scheduling functions associated with the DWR contracts allocated to their customers. The IOUs continue to act as billing and collection agents for the DWR.

Local Regulation, Licenses and Permits

Pacific Gas and Electric Company obtains a number of permits, authorizations, and licenses in connection with the construction and operation of its generating plants, transmission lines, and gas compressor station facilities. Discharge permits, various Air Pollution Control District permits, U.S. Department of Agriculture-Forest Service permits, FERC hydroelectric facility and transmission line licenses, and NRC licenses are the most significant examples. Some licenses and permits may be revoked or modified by the granting agency if facts develop or events occur that differ significantly from the facts and projections assumed in granting the approval. Furthermore, discharge permits and other approvals and licenses are granted for a term less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. The Utility currently has eight hydroelectric projects and one transmission line project undergoing FERC license renewal.

The Utility has over 520 franchise agreements with various cities and counties that allow the Utility to install, operate and maintain its electric, natural gas, oil, and water facilities in the public streets and roads. In exchange for the right to use public streets and roads, the Utility pays annual fees to the cities and counties under the franchises. Franchise fees are computed according to statute depending on whether the particular franchise was granted under the Broughton Act or the Franchise Act of 1937; however, there are 38 "charter cities" that can set a fee of their own determination. The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas. Pursuant to the permits, licenses, and franchises, the Utility has rights to occupy and/or use public property for the operation of its business and to conduct certain operations.

The Utility's operations and assets are also regulated by a variety of other federal, state, and local agencies.

Regulation of PG&E National Energy Group, Inc. Businesses

Federal Regulation

The rates, terms, and conditions of the wholesale sale of power by the generating facilities owned or leased by PG&E NEG through PG&E Generating Company LLC, its subsidiaries and affiliates, and of power contractually controlled by them is subject to FERC jurisdiction under the Federal Power Act. Various PG&E NEG subsidiaries and affiliates have FERC-approved market-based rate schedules and accordingly have been granted waivers of many of the accounting, record keeping, and reporting requirements imposed on entities with cost-based rate schedules. This market-based rate authority may be revoked or limited at any time by the FERC.

PG&E NEG-affiliated projects are also subject to other differing federal regulatory regimes. Those qualifying as qualifying facilities, or QFs, under the Public Utility Regulatory Policies Act of 1978, or

PURPA, are exempt from the Holding Company Act, certain rate filings, and accounting, record keeping, and reporting requirements that the FERC otherwise imposes and from certain state laws. Others qualify as Exempt Wholesale Generators under the National Energy Policy Act of 1992. These generators are not regulated under the Holding Company Act, but are subject to FERC and state regulation, including rate approval.

The FERC also regulates the rates, terms, and conditions for electric transmission in interstate commerce. Tariffs established under FERC regulation provide PG&E NEG with the necessary access to transmission lines which enables PG&E NEG to sell the energy PG&E NEG produces into competitive markets for wholesale energy. In April 1996, the FERC issued an order requiring all public utilities to file "open access" transmission tariffs. Some utilities are seeking permission from the FERC to recover costs associated with stranded investments through add-ons to their transmission rates. To the extent that the FERC will permit these charges, the cost of transmission may be significantly increased and may affect the cost of PG&E NEG operations.

The FERC also licenses all of PG&E NEG's hydroelectric and pumped storage projects. These licenses, which are issued for 30 to 50 years, will expire at different times between 2002 and 2020. The relicensing process often involves complex administrative processes that may take as long as 10 years. The FERC may issue a new license to the existing licensee, issue a license to a new licensee, order that the project be taken over by the federal government (with compensation to the licensee), or order the decommissioning of the project at the owner's expense.

PG&E NEG's natural gas transmission business is also subject to FERC jurisdiction. Certificates of public convenience and necessity have been obtained from the FERC for construction and operation of the existing pipelines and related facilities and properties, construction and operation of the North Baja Pipeline, and construction and operation on the PG&E GTN pipeline currently underway. An application has also been filed with the FERC to construct a further expansion on PG&E GTN. The rates, terms, and conditions of the transportation and sale (for resale) of natural gas in interstate commerce is subject to FERC jurisdiction. As necessary, PG&E NEG subsidiaries and affiliates file applications with the FERC for changes in rates and charges that allow recovery of costs of providing services to transportation customers. An October 1999 order permits individually negotiated rates in certain circumstances.

The U.S. Department of Energy, or DOE, also regulates the importation of natural gas from Canada and exportation of power to Canada.

State and Other Regulations

In addition to federal laws and regulation, PG&E NEG businesses are also subject to various state regulations. First, public utility regulatory commissions at the state level are responsible for approving rates and other terms and conditions under which public utilities purchase electric power from independent power projects. As a result, power sales agreements, which PG&E NEG affiliates enter into with such utilities, are potentially subject to review by the public utility commissions, through the commissions' power to approve utilities' rates and cost recoveries. Second, state public utility commissions also have the authority to promulgate regulations for implementing some federal laws, including certain aspects of PURPA. Third, some public utility commissions have asserted limited jurisdiction over independent power producers. For example, in New York the state public utility commission has imposed limited requirements involving safety, reliability, construction, and the issuance of securities by subsidiaries operating assets located in that state. Fourth, state regulators have jurisdiction over the restructuring of retail electric markets and related deregulation of their electric markets. Finally, states may also assert jurisdiction over the siting, construction, and operation of PG&E NEG's generation facilities.

In addition, the National Energy Board of Canada and the Canadian gas-exporting provinces issue licenses and permits for removal of natural gas from Canada. The Mexican Comisión Reguladoro de

Energía, or CRE, issues various licenses and permits for the importation of gas into Mexico. These requirements are similar to the requirements of the U.S. Department of Energy for the importation and exportation of gas.

Other regulatory matters are described throughout this report. For a discussion of environmental regulations to which PG&E Corporation and its subsidiaries are subject, see the section entitled "Environmental Matters" below.

COMPETITION

Historically, energy utilities operated as regulated monopolies within specific service territories where they were essentially the sole suppliers of natural gas and electricity services. Under this model, the energy utilities owned and operated all of the businesses necessary to procure, generate, transport, and distribute energy. These services were priced on a combined, or "bundled" basis, with rates charged by the energy companies designed to include all of the costs of providing these services. Under traditional cost-of-service regulation, there is a regulatory compact in which the utilities undertake a continuing obligation under state law to serve their customers, in return for which the utilities are authorized to charge regulated rates sufficient to recover their costs of service, including timely recovery of their operating expenses and a reasonable return on their invested capital. The objective of this regulatory policy was to provide universal access to safe and reliable utility services. Regulation was designed in part to take the place of competition and ensure that these services were provided at fair prices. In recent years, energy utilities faced intensifying pressures to "unbundle," or price separately, those activities that are no longer considered natural monopoly services. The most significant of these were the commodity components electricity and natural gas.

The driving forces behind these competitive pressures have been customers who believe they can obtain energy at lower unit prices and competitors who want access to those customers. Regulators and legislators responded to these customers and competitors by providing for more competition in the energy industry. Regulators and legislators required utilities to unbundle rates in order to allow customers to compare unit prices of the utilities and other providers when selecting their energy service provider.

The Electric Industry

As discussed above, in 1998, California implemented AB 1890, which mandated the restructuring of the California electric industry 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.

During the first two years of the transition period, the revenues from frozen retail rates exceeded the generation costs included in retail rates. Beginning in June 2000, wholesale prices for electricity in California began to increase. Prices moderated somewhat in the fall of 2000, before increasing to unprecedented levels in mid-November of 2000 and later months. Revenues from the Utility's frozen retail rates were insufficient to recover the cost of purchasing wholesale power. In January 2001, as wholesale power prices continued to far exceed retail rates, the major credit rating agencies lowered their ratings for the Utility and PG&E Corporation to non-investment grade levels. Consequently, the Utility lost access to its bank facilities and the capital markets, and could no longer continue buying power to deliver to its customers. As a result, the California legislature authorized the DWR to purchase electricity for the Utility's customers. The DWR's authority to enter into new contracts or purchase power on the spot market expired on December 31, 2002. On January 1, 2003, the California IOUs resumed procuring power to cover their retail customers' residual net open position.

The FERC's policy has supported the development of a competitive electric generation sector. The FERC's Order 888, issued in 1996, established standard terms and conditions for parties seeking access to regulated utilities' transmission grids. The FERC's subsequent Order 2000, issued in 1999,

established national standards for RTOs and advanced the view that a regulated, unbundled transmission sector should facilitate competition in both wholesale electric generation and retail electricity markets. The FERC's more recent standard market design proposal continues to uphold this view.

The Utility faces increased competition in the electricity distribution function as a result of the construction of duplicate distribution facilities to service specific existing or new customers, potential municipalization of the Utility's existing distribution facilities by a local government or district, self-generation by the Utility's customers, and other forms of competition that may result in stranded investment capital, loss of customer growth and additional barriers to cost recovery. If the number of Utility customers declines due to these forms of competition and the Utility's rates are not increased in a timely manner to allow the Utility to fully recover its investment and procurement costs, the Utility's financial condition and results of operations could be materially adversely affected.

The Natural Gas Industry

FERC Order 636, issued in 1992, required interstate pipeline companies to divide their services into separate gas commodity sales, transportation, and storage services. Under Order 636, interstate gas pipelines must provide transportation service regardless of whether the customer (often a local gas distribution company) buys the gas commodity from the pipeline.

In August 1997, the CPUC approved the Gas Accord settlement agreement, or Gas Accord, which restructured the Utility's gas services and its role in the gas market through 2002. Among other matters, the Gas Accord unbundled the rates for the Utility's gas transportation services from the rates for its distribution services. As a result, the Utility's customers may buy gas directly from competing suppliers and purchase transportation-only and distribution-only services from the Utility. The Utility's industrial and larger commercial customers, or noncore customers, now purchase their gas from producers, marketers and brokers. Substantially all residential and smaller commercial customers, or core customers, buy gas as well as transmission and distribution services from the Utility as a bundled service.

Although the Gas Accord originally was scheduled to expire on December 31, 2002, the Utility filed an application to extend the Gas Accord for two years, known as the Gas Accord II Application, or Gas Accord II. In August 2002, the CPUC approved a settlement agreement among the Utility and other parties that provided for a one-year extension through 2003 of the Utility's existing gas transportation and storage rates and terms and conditions of service, as well as rules governing contract extensions and an open season for new contracts. The Gas Accord II settlement left open to subsequent litigation the issues raised in the application insofar as they relate to the second year of the two-year application. In January 2003, the Utility filed an application proposing Gas Accord II rates for 2004. For more information about the Gas Accord and regulatory changes affecting the California natural gas industry, see "Utility Operations Ratemaking Machanisms Gas Ratemaking" below.

The Utility competes with other natural gas pipeline companies for transportation customers into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas and the quality and reliability of transportation services. The most important competitive factor affecting the Utility's market share for transportation of gas to the southern California market is the total cost of western Canadian gas, including transportation costs, delivered to southern California from the Utility's transportation system relative to the total cost of gas, including transportation costs, delivered to southern California on other pipeline systems from supply basins in the southwestern United States and Rocky Mountains. In general, when the total cost of western Canadian gas increases, the Utility's market share in southern California decreases. In addition, Kern River Pipeline Company expects to complete a major expansion of its pipeline system in 2003 that will increase its capacity to deliver natural gas into the southern California market by approximately 900 million cubic feet, or MMcf, per day. As a result of Kern River's expansion, the volume of gas that

the Utility delivers to the southern California market may decrease in the short term. The Utility also competes for storage services with other third party storage providers, primarily in northern California. The most important competitive factors affecting the Utility's market share are overall product design and pricing terms.

From time to time, existing pipeline companies propose to expand their pipeline systems for delivery of natural gas into northern and central California. Although the record gas-fired electric generation gas demands in late 2000 and 2001 spurred several new natural gas pipeline proposals for northern and central California, many of the power generation projects have been cancelled or delayed, making it difficult for sponsors of the various gas pipeline projects to acquire enough firm capacity commitments to go forward with construction.

Electric Generation and Natural Gas Transmission

During 2002, adverse changes in the national energy markets affected PG&E NEG's business including:

- Contractions and instability of wholesale electricity and energy commodity markets;
- Significant decline in generation margins (spark spreads) caused by excess supply and reduced demand in most regions of the United States;
- Loss of confidence in energy companies due to increased scrutiny by regulators, elected officials, and investors as a result of a string of financial reporting scandals;
- Heightened scrutiny by credit rating agencies prompted by these market changes and scandals which resulted in lower credit ratings for many market participants; and
- Resulting significant financial distress and liquidity problems among market participants leading to numerous financial restructurings and less market participation.

PG&E NEG has been significantly impacted by these adverse changes. New generation came online while the demand for power was dropping. This oversupply and reduced demand resulted in low spark spreads (the net of power prices less fuel costs) and depressed operating margins. These changes in the energy industry have had a significant negative impact on the financial results and liquidity of PG&E NEG as discussed in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Competitive factors may also affect the results of PG&E NEG's operations including new market entrants (e.g. construction by others of more efficient generation assets), retirements, and a participant's number of years and extent of operations in a particular energy market. PG&E NEG's Generation Business competes against a number of other participants in the merchant energy industry including Mirant, Calpine, Duke Energy, Reliant, AES, and NRG. Competitive factors relevant to this industry include financial resources, credit quality, development expertise, insight into market prices, conditions and regulatory factors, and community relations. PG&E NEG's competitors have greater financial resources than PG&E NEG does and have a lower cost of capital.

When economic circumstance force fuel suppliers into bankruptcy, fuel supply contracts are at risk of being terminated, especially if the current market prices are substantially higher than the prices committed to in long-term contracts. Under such circumstances, PG&E NEG is at risk for having its power sales agreements and fuel supply agreements uncoupled. As states review the need for electric industry restructuring, there is a risk that current contracts are found to be too expensive and attempts may be made to abrogate such contracts.

PG&E NEG's Pipeline Business competes with other pipeline companies for transportation customers on the basis of transportation rates, access to competitively priced gas supply and growing markets, and the quality and reliability of transportation services. The competitiveness of a pipeline's transportation services to any market is generally determined by the total delivered natural gas price from a particular natural gas supply basin to the market served by the pipeline. The cost of transportation on the pipeline is only one component of the total delivered cost.

PG&E NEG's transportation service on the PG&E GTN pipeline accesses supplies of natural gas primarily from western Canada and serves markets in the Pacific Northwest, California and Nevada. PG&E NEG must compete with other pipelines for access to natural gas supplies in western Canada. PG&E NEG's major competitors for transportation services for western Canadian natural gas supplies include TransCanada Pipelines, Alliance Pipeline, Southern Crossing Pipeline and Northern Border Pipeline Company and Westcoast Energy Gas Transmission.

The three markets PG&E NEG serves may access supplies from several competing basins in addition to supplies from western Canada. Historically, natural gas supplies from western Canada have been competitively priced on the PG&E GTN pipeline in relation to natural gas supplied from the other supply regions serving these markets. Supplies transported from western Canada on the PG&E GTN pipeline compete in the California market with Rocky Mountain natural gas supplies delivered by Kern River Gas Pipeline and Southwest natural gas supplies delivered by Transwestern Pipeline Company, El Paso Natural Gas and Southern Trails Pipeline. In the Pacific Northwest market, supplies transported from western Canada on the PG&E GTN pipeline compete with Rocky Mountain gas supplies delivered by Northwest Pipeline Corporation and with British Columbia supplies delivered by Westcoast Transmission Company for redelivery by Northwest Pipeline Corporation.

Transportation service on NBP provides access to natural gas supplies from both the Permian basin, located in western Texas and southeastern New Mexico, and the San Juan basin, primarily located in northwestern New Mexico. The North Baja system delivers gas to Gasoducto Bajanorte Pipeline, at the Baja California California border, which transports the gas to markets in northern Baja California, Mexico. While there are currently no direct competitors to deliver natural gas to NBP's downstream markets, the pipeline may compete with fuel oil which is an alternative to natural gas in the operation of some electric generation plants in the North Baja region. Moreover, NBP's market is near locations of interest for liquefied natural gas development companies who may be interested in delivering foreign natural gas supplies to the area.

Overall, PG&E NEG's transportation volumes are also affected by other factors such as the availability and economic attractiveness of other energy sources. Hydroelectric generation, for example, may become available based on ample snowfall and displace demand for natural gas as a fuel for electric generation. Finally, in providing interruptible and short-term transportation service, PG&E NEG competes with release capacity offered by shippers holding firm contract capacity on PG&E NEG's pipelines.

UTILITY OPERATIONS

The Utility is the principal provider of electricity and natural gas distribution and transmission services in northern and central California. The Utility's service territory covers 70,000 square miles, serving 4.8 million electricity customers and 4.0 million natural gas customers.

Ratemaking Mechanisms

In setting the retail rates for the Utility's electric and natural gas utility services, the CPUC first determines the Utility's revenue requirements. The components of revenue requirements for electric and natural gas utility service include depreciation, expenses, taxes, and return on investment, as applicable, for distribution, transmission/transportation, generation/procurement, and public purpose programs. The CPUC then allocates the revenue requirements among customer classes (mainly residential, commercial, industrial, and agricultural) and sets specific rates designed to produce the required revenue. The concept underpinning the determination of revenue requirements and rates is to allow a utility a fair opportunity to recover its reasonable costs of providing adequate utility service, including a reasonable rate of return of and on its investment in utility facilities.

The primary revenue requirement proceeding is the general rate case, or GRC. In the GRC, the CPUC authorizes the Utility to collect from ratepayers an amount known as "base revenues" to recover basic business and operational costs for its natural gas and electricity operations. The general rate case sets annual revenue requirement levels for a three-year rate period. The CPUC authorizes these revenue requirements in general rate case proceedings generally every three years based on a forecast of costs for the first or "test" year. The Utility's pending general rate case request is for test year 2003. For the remaining two years of a general rate case period, the Utility has indicated that it intends to apply for annual increases in base revenues (known as attrition rate adjustments) to reflect inflation and increases in invested capital. After authorizing the revenue requirement, the CPUC allocates revenue requirements among customer classes and establishes specific rate levels in separate proceedings.

Another major CPUC proceeding for determining revenue requirements is the annual cost of capital proceeding. Each year, the CPUC determines the adopted rate of return that the Utility may earn on its electric and gas distribution assets and recover from ratepayers. On November 7, 2002, the CPUC issued a final decision that retained the Utility's return on common equity at the current authorized level of 11.22%. This final decision also increased the Utility's authorized cost of debt to 7.57% from 7.26%, and held in place the current authorized capital structure of 48% common equity, 46.2% long-term debt, and 5.8% preferred equity. The final decision also holds open the proceeding to address the impact on the Utility's return on equity, costs of debt and preferred stock, and ratemaking capital structure of the implementation and financing of a bankruptcy plan of reorganization.

The return on the Utility's electric transmission-related assets is determined by the FERC. See "Electric Ratemaking" below. The return on the Utility's natural gas transmission and storage business was incorporated in rates established in the Gas Accord. See "Gas Ratemaking" below.

Electric Ratemaking

As required by AB 1890, electric rates for all customers were frozen at the level in effect on June 10, 1996, and, beginning January 1, 1998, rates for residential and small commercial customers were further reduced by 10%. In the first quarter of 2001, the CPUC authorized the Utility to begin collecting energy surcharges totaling $0.04 per kWh (composed of a $0.01 per kWh surcharge approved in January and a $0.03 per kWh surcharge approved in March). Although the CPUC authorized the $0.03 per kWh surcharge in March 2001, the Utility did not begin collecting the revenues until June 2001. As a result, in May 2001, the CPUC authorized the Utility to collect an additional $0.005 per kWh surcharge revenue for 12 months to make up for the time lag in collection of the $0.03 surcharge revenues. Although the collection of this "half-cent surcharge" was originally scheduled to end on May 31, 2002, the CPUC issued a resolution ordering the Utility to continue collecting the half-cent surcharge until further consideration by the CPUC. The CPUC initially restricted the use of these surcharge revenues to pay for the Utility's "ongoing procurement costs" and "future power purchases."

Under AB 1890, the rate freeze was supposed to end on the earlier of March 31, 2002, or when the Utility had recovered its eligible transition costs. Most transition costs must be recovered during a transition period that ends the earlier of December 31, 2001, or when the Utility had recovered its eligible transition costs. The Utility repeatedly has advised the CPUC that it had recovered all of its transition costs and has asked the CPUC to recognize that the rate freeze already has ended for the Utility's customers. After the rate freeze, changes in the Utility's electric revenue requirements in general will be reflected in rates. However, the CPUC has not yet determined that the rate freeze has ended for the Utility's customers.

After the CPUC has determined when the Utility's rate freeze ended, the Utility expects the CPUC to set rates to recover:

- the Utility's approved utility cost components,

- the cost of energy sold to customers, and
- the DWR's revenue requirement allocated to the Utility's customers.

The Utility refers to this structure as "bottoms-up" billing. At this time, the Utility does not know when or under what conditions the CPUC will determine that the Utility's rate freeze has ended and the Utility will begin bottoms-up billing or to which periods these rates would apply.

In April 2001, the California Public Utilities Code was amended to require that the CPUC ensure that errors in estimates of demand elasticity or sales by the Utility do not result in material over or undercollections of costs by the Utility. The Utility intends to address implementation of this new law in connection with pending proceedings at the CPUC relating to recovery of components of its costs of service.

Electric Distribution.

2003 General Rate Case. On November 8, 2002, the Utility filed its 2003 general rate case application requesting an increase in electric revenue requirements of $447 million over the current authorized amount of $2.269 billion to maintain current service levels to existing customers, and to adjust for wages and inflation. The Utility also indicated that it will seek an attrition rate adjustment increase for 2004 and 2005. The attrition rate adjustment mechanism is designed to avoid a reduction in earnings in years between general rate cases to reflect increases in rate base and expenses. The CPUC has ruled that the revenue requirements to be determined in the Utility's 2003 general rate case will be effective January 1, 2003, even though the CPUC will not issue a final decision on the 2003 GRC until after that date. The Utility cannot predict what amount of revenue requirements, if any, the CPUC will authorize for the 2003 through 2005 period. The administrative law judge presiding over the 2003 GRC has adopted a schedule for this proceeding that includes a target date of February 5, 2004.

2002 Attrition Rate Adjustment Request. In the 2003 GRC, the CPUC asked parties to comment on the Utility's need for a 2002 attrition rate adjustment. The Utility informed the CPUC in November 2001 that the Utility would need a 2002 attrition rate adjustment to recover escalating electric and gas distribution service costs. In April 2002, the CPUC issued a ruling authorizing any attrition rate adjustment that ultimately may be granted to become effective as of April 22, 2002. In June 2002, the Utility filed its application, requesting a $76.7 million increase to its annual electric distribution revenue requirement, and a $19.5 million increase to its annual gas distribution revenue requirement. In December 2002 a proposed decision was issued that would deny this request. The Utility filed comments in late December 2002 arguing that the proposed decision was based on a fundamental misunderstanding of the facts. In February 2003 an alternate proposed decision was issued that would grant a $63.5 million increase to the Utility's annual electric distribution revenue requirement, and a $10.3 million increase to the Utility's annual gas distribution revenue requirement. A final decision is expected to be issued in the first quarter of 2003.

Baseline Allowance Increase. On April 9, 2002, the CPUC issued a decision that required the Utility to increase baseline allowances for certain residential customers by May 1, 2002. An increase to a customer's baseline allowance increases the amount of their monthly usage that will be covered under the lowest possible rate and that is exempt from surcharges. The decision deferred consideration of corresponding rate changes until a later phase of the proceeding and ordered the Utility to track the undercollections associated with these baseline quantity changes in an interest-bearing balancing account. The Utility estimates the annual revenue shortfall to be approximately $96 million for electricity service, and $6 million for natural gas service. The total electricity revenue shortfall estimated for the period May through December 2002 was $70 million.

In the second phase of the proceeding, the CPUC will consider issues involving demographic revisions to baseline allowances, a special allowance for well water pumping, revisions applicable to usage at vacation homes, and changes to baseline territories or seasons. The resolution of these issues

could result in an additional revenue shortfall of approximately $102 million spread out over three to five years. Hearings on these issues concluded in September 2002 and a final CPUC decision is expected to be issued in early 2003. The Utility has charged the electricity revenue shortfall to earnings and will continue to charge the shortfall to earnings. This charge reduces revenue available to recover the Utility's previously written-off undercollected power procurement costs and transition costs.

Electric Transmission

Electric transmission revenues, and both wholesale and retail transmission rates, are subject to authorization by the FERC. The Utility has two sources of transmission revenues, those from charges under its transmission owner tariff, or TO Tariff, and those from charges under specific contracts with existing wholesale transmission customers that pre-date the Utility's participation in the ISO. Customers that receive transmission services under such pre-existing contracts, referred to as existing transmission contract customers, or ETC customers, are charged individualized rates based on the terms of their respective contracts. The Utility's ETC customers include various municipal utilities and state and federal agencies. These customers typically own and operate distribution systems that carry electricity to municipal, state or federal facilities, such as city halls, and the water pumps along the California aqueduct. The Utility's municipal utility ETC customers distribute electricity to municipal facilities and, in many cases to the homes and businesses of retail electricity customers located inside their municipality.

Under the FERC's regulatory regime, the Utility is able to file a new base transmission rate case under the Utility's TO Tariff whenever the Utility deems it necessary to increase its rates. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process.

The Utility's TO Tariff includes two rate components: (1) base transmission rates (from which the Utility derives the majority of its transmission revenues) which are intended to recover the Utility's operating and maintenance expenses, depreciation and amortization expenses, interest expense, tax expense and return on equity and (2) the rates the Utility charges its TO Tariff customers to recover various bills the Utility receives from the ISO for reliability service costs, and the ISO's transition charge associated with the ISO's high-voltage blended rate methodology.

Transmission Owner Rate Cases. On January 29, 2003, the FERC approved a settlement filed by the Utility that allows the Utility to recover $292 million on an annual basis from March 31, 1998 until October 29, 1998 and $316 million on an annual basis from October 30, 1998 until May 30, 1999 in TO Tariff electric transmission rates. During that period, somewhat higher rates were collected, subject to refund. As a result of the approval, the Utility will refund $30 million it had accrued for potential refunds related to the 14-month period ended May 30, 1999. In April 2000, the FERC approved a settlement that permitted the Utility to recover $329 million on an annual basis in TO Tariff electric transmission rates retroactively for the 10-month period from May 31, 1999 to March 31, 2000. In September 2000, the FERC approved another settlement that permitted the Utility to recover $352 million annually in TO Tariff electric transmission rates and made this retroactive to April 1, 2000. Further, in July 2001, the FERC approved another settlement that permits the Utility to collect $379 million annually in TO Tariff electric transmission rates retroactive to May 6, 2001. The transmission rates charged to TO Tariff customers are adjusted for other transmission revenue credits related to ISO congestion management charges and other transmission related services billed by the ISO and remitted to the Utility as a transmission owner.

On January 13, 2003, the Utility filed an application requesting to recover $545 million in electric retail transmission rates annually, a 44% increase over the revenue requirement currently in effect. The requested increase is mainly attributable to significant capital additions made to the Utility's system to accommodate load growth, to maintain the infrastructure, and to ensure safe and reliable service. In addition, the request includes a 15-year useful life for transmission plant coming into service in 2003

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and a return on equity of 13.5%. The January 13 filing date will allow proposed rates to go into effect, subject to refund, no later than August 13, 2003.

The Utility recovers certain ISO costs described below in balancing accounts. In general, for each of these types of costs, the difference between the ISO's actual charges and revenues collected by the Utility and the forecasted costs will be used to either offset or increase the specific revenue requirement for such costs for the next period when the Utility files an annual balancing account rate case related to such costs.

Reliability Services Costs The ISO bills the Utility for reliability services based on payments that the ISO makes to generators under reliability must-run contracts and for locational out-of-market calls required to support reliability of the transmission system. The Utility charges its customers rates designed to recover these reliability service charges, without mark-up or service fees. The Utility records these customer charges as operating revenue, and records a corresponding expense under its cost of power line item to reflect the fact that the Utility must pass this revenue on to the ISO. Costs and revenues related to reliability services are tracked in the reliability services balancing account.

Transition Charges Beginning on January 1, 2001, the Utility pays the ISO's high-voltage blended transmission rate which is higher than the Utility-specific high-voltage transmission rate. The difference between the ISO's rate and the Utility's rate is tracked in the Utility's transmission access charge balancing account and will be collected once frozen retail rates are changed by the CPUC.

Grid Management Costs. The ISO also bills the Utility for grid management services attributable to the Utility's ETC customers. These grid management services costs are passed on to the Utility's ETC customers through the Grid Management Charge Tariff. The Utility records grid management costs billed by the ISO in operating and maintenance expenses and passes these costs to its ETC customers, without mark-up or service fees, subject to refund pending the outcome of the FERC ratemaking review process expected to take place in the first half of 2003.

Scheduling Coordinator Costs. The Utility serves as the scheduling coordinator to schedule transmission with the ISO for its ETC customers. The ISO bills the Utility for providing certain services associated with these contracts. These ISO charges are referred to as the "scheduling coordinator costs." These costs historically have been tracked in the transmission revenue balancing account, or TRBA, in order for the Utility to recover these costs from its TO Tariff customers. In 2002, the FERC ruled that the Utility should refund to TO Tariff customers the scheduling coordinator costs that the Utility collected from them. As of December 31, 2002, TO Tariff customers had already paid the Utility $107 million for these costs.

In January 2000, the FERC accepted a filing by the Utility to establish a separate tariff to allow the Utility to recover both the shortfall and future scheduling coordinator costs from its ETC customers. The FERC has authorized the separate tariff, subject to refund, which has been challenged by ETC customers. For the period beginning April 1998 through December 31, 2002, the Utility transferred $107 million of scheduling coordinator costs from the TRBA to accounts receivable net of a $66 million reserve for potential uncollectible costs. The Utility also has disputed approximately $27 million of these costs as incorrectly billed by the ISO.

Electric Generation

The CPUC has approved a 2002 revenue requirement of $3 billion for recovery of costs of generation that the Utility retains, including purchased power expenses, depreciation, operating expenses, taxes, and return on investment, based on the net regulatory value of generation assets as of December 31, 2000. The Utility's retained generation costs incurred in 2002 are subject to reasonableness review. A pending proposal by The Utility Reform Network, or TURN, a non-profit

organization representing small utility customers, would continue this treatment. Before 2002, these costs have been forecast as with other costs in the general rate case, with rates set to recover the forecast, regardless of actual cost.

The Utility's 2003 revenue requirement for retained generation is being considered in the Utility's 2003 general rate case proceeding. The Utility's 2003 general rate case application, as updated on February 20, 2003, requested an increase in non-fuel generation revenue requirements of $149 million from $872 million, the amount currently authorized. This requested revenue requirement excludes the Utility's estimated fuel and procurement costs recorded in the Energy Resource Recovery Account, or ERRA, and the DWR's power charges.

Electric Procurement

2001 Annual Transition Cost Proceeding: Review of Reasonableness of Electric Procurement. On January 11, 2002, as directed by the CPUC, the Utility filed a report at the CPUC detailing the reasonableness of the Utility's electric procurement and generation scheduling and dispatch activities for the period July 1, 2000 through June 30, 2001. In this proceeding, the CPUC will review the reasonableness of the Utility's procurement of wholesale electricity from the PX and the ISO during the height of the 2000-2001 California energy crisis. With the exception of a limited right to purchase electricity from third parties beginning in August 2000, all of the Utility's wholesale power purchases during this period were required to be made exclusively from or through the PX and ISO markets pursuant to FERC-approved tariffs. Prior CPUC decisions have determined that such purchases should be deemed reasonable. In addition, the Utility's complaint against the CPUC Commissioners asserts that the costs of such purchases are recoverable in the Utility's retail rates without further review by the CPUC under the federal filed rate doctrine. However, an administrative law judge of the CPUC is asserting jurisdiction to review the reasonableness of the Utility's wholesale electricity purchases from the PX and ISO in the proceeding. A report from the CPUC's Office of Ratepayer Advocates regarding the Utility's procurement activities for the covered period is due April 28, 2003. It is possible that this proceeding could result in some disallowance of the Utility's costs incurred during the 2000-2001 period associated with its purchases from the PX and ISO markets.

Energy Resource Recovery Account, or ERRA. As of January 1, 2003, the California IOUs have resumed procuring electricity to meet the amount of their customers' electricity needs that cannot be met with utility-owned generation, electricity supplied under QF and other contracts, and electricity allocated to their customers under the DWR contracts. Effective January 1, 2003, the Utility established the Energy Resource Recovery Account, or ERRA, to record and recover electricity costs, excluding the DWR's power contract costs, associated with the Utility's authorized procurement plan. Electricity costs recorded in ERRA include, but are not limited to, fuel costs for retained generation, QF contracts, inter-utility contracts, ISO charges, irrigation district contracts and other power purchase agreements, bilateral contracts, forward hedges, pre-payments and collateral requirements associated with procurement (including disposition of surplus electricity), and ancillary services. The Utility offsets these costs by reliability-must-run revenues, the Utility's allocation of surplus sales revenues and the ERRA revenue requirement. The CPUC has authorized the Utility to file an expedited trigger application at any time that its forecast indicates the undercollection in the ERRA will be in excess of 5% of the Utility's recorded generation revenues for the prior year excluding amounts collected for the DWR. The Utility currently estimates that its 5% threshold amount will be approximately $224 million. When filing an expedited trigger application, the CPUC has directed the Utility to propose an amortization period of not less than 90 days for the undercollected amount to insure timely recovery. The CPUC has approved, on a preliminary basis, a starting ERRA revenue requirement of $2.035 billion for the Utility.

On February 3, 2003, the Utility filed its 2003 ERRA forecast application requesting that the CPUC reset the Utility's 2003 ERRA revenue requirement to $1.413 billion and that the ERRA trigger threshold of $224 million be adopted. The CPUC will examine the Utility's forecast of costs for 2003

and will finalize the Utility's starting ERRA revenue requirement and ERRA trigger threshold when it reviews the Utility's ERRA application.

Qualifying Facilities and Other Existing Bilateral Agreements. Costs of the Utility's existing contracts with qualifying facilities and other electricity providers are passed through to ratepayers dollar for dollar as approved by the CPUC in the retained generation ratemaking proceeding for 2002 and generation procurement proceeding for 2003. See "Electric Generation" and "Electric Resource Recovery Account" discussions, above.

Direct Access. To avoid a shift of costs from direct access customers to bundled customers, the CPUC has established a direct access cost responsibility surcharge, or CRS, to implement utility-specified non-bypassable charges on direct access customers for their share of the bond costs and power costs incurred by the DWR and above-market cost related to the Utility's own generation resources and power contracts. The decision establishes four components comprising the CRS:

DWR Bond Charge. This charge is applicable to all direct access customers, except customers who were on direct access before the DWR began purchasing power and have continued to remain on direct access since the DWR began purchasing power (continuous direct access customers). The bond charge for direct access customers will include amounts accruing since November 15, 2002. The actual amount of this charge on direct access customers is being determined in the DWR bond charge allocation proceeding.

DWR Electricity Charge for the September 21, 2001, through December 31, 2002 Period. This charge is applicable to direct access customers who previously took bundled service at any time on or after February 1, 2001. The charge is designed to recover direct access customers' share of the DWR's procurement costs between September 21, 2001, and December 31, 2002. Since bundled customers already have paid this amount to the DWR, these charges collected from direct access customers would reduce the amount of bundled customers' bills remitted to the DWR.

DWR Electricity Charge for Future DWR Costs. This charge is applicable to direct access customers who previously took bundled service at any time on or after February 1, 2001. This charge is designed to recover direct access customers' share of the uneconomic portion of the DWR's procurement costs for 2003 and thereafter. This charge will be adjusted on an annual basis or more frequently if the DWR's revenue requirement is adjusted more frequently.

The Utility's Procurement and Generation Charge. This charge is applicable to all direct access customers regardless of the date on which a customer switched to direct access. This charge is designed to recover direct access customers' share of the ongoing uneconomic portion of the Utility's generation and procurement costs. This charge will be based on an estimate of above-market costs for the Utility's procurement contracts and qualifying facility arrangements, which in turn is based on a $0.043 per kWh benchmark for 2003. This benchmark for determining above-market costs will be updated annually.

The decision imposes a cap on the CRS of $0.027 cents per kWh which was implemented on January 1, 2003. The CPUC has indicated that it will establish an expedited review schedule to determine whether the cap should be adjusted and has set a goal of reaching a decision on whether this cap should be adjusted, and whether trigger mechanisms for adjusting the cap would be established, by July 1, 2003.

Funds remitted under the CRS will be applied first to the DWR bond charges, second to the DWR electricity charges, and third to the Utility's ongoing procurement and generation costs. Direct access customers who have returned to bundled service will be responsible for their share of the unrecovered costs resulting from the CRS. To the extent the cap results in an undercollection of DWR charges, the shortfall would have to be remitted to DWR from bundled customers' funds. Interest on undercollections will be assessed at the DWR's bond interest rate on an interim basis while the CPUC examines a long-term plan for financing the CRS. The Utility does not expect that the CPUC's implementation of this decision or the level of the CRS cap will have a material adverse effect on its results of operations or financial condition.

DWR Revenue Requirements, Servicing Order and Operating Order. The CPUC has adopted rates for the DWR that allow the DWR to collect electricity and bond-related charges from ratepayers to recover what it spent to procure electricity for the customers of the California IOUs during 2001 and 2002. The recovery is being financed partially through a statewide revenue requirement allocated among the three California IOUs and partially through the DWR's November 2002 issuance of $11.3 billion in revenue bonds, which will be repaid by the customers of the three California IOUs through the bond charge discussed below. In February 2002, the CPUC approved a decision that set the statewide DWR revenue requirement for 2001 and 2002. In March 2002, the CPUC reallocated the amounts contained in the February 2002 decision among the customers of the three California IOUs. The March 2002 decision allocated $4.4 billion of a total statewide power charge revenue requirement of approximately $9.0 billion to the Utility's customers. Of the $4.4 billion allocated to the customers of the Utility, approximately $2.6 billion related to 2001 power charges and approximately $1.8 billion related to 2002 power charges. In December 2002, the CPUC issued a decision allocating approximately $2 billion of the DWR's 2003 power charge-related revenue requirements to the Utility's customers. This revenue requirement includes the variable costs of the DWR contracts allocated to the Utility's customers by an earlier decision in September 2002. The DWR plans to submit a revised 2003 power charge-related revenue requirement to the CPUC in late March 2003. A separate proceeding will consider a revision or true-up for the revenue requirements remitted to the DWR for 2001 and 2002 costs, once final 2002 cost data is available. This true-up proceeding is scheduled for April 2003.

Before the DWR's 2003 statewide revenue requirement filing with the CPUC in August 2002, the Utility filed comments with the DWR alleging that major portions of the DWR's revenue requirements were not "just and reasonable" as required by AB 1X and that the DWR was not complying with the procedural requirements of AB 1X in making its determination. On August 26, 2002, the Utility filed with the DWR a motion for reconsideration of the DWR's determination that its revenue requirements were "just and reasonable." The DWR denied the Utility's motion on October 8, 2002. On October 17, 2002, the Utility filed a lawsuit in a California court asking the court to find that the DWR's revenue requirements had not been demonstrated to be "just and reasonable" and lawful, and that the DWR had violated the procedural requirements of AB 1X in making its determination. In part, the Utility based its allegations on the State of California's petition pending before the FERC seeking to set aside many of the DWR contracts on the basis that they are not "just and reasonable." The Utility asked that the court order that the DWR's revenue requirement determination be withdrawn as invalid, and that the DWR be precluded from imposing its revenue requirements on the Utility and its customers until it has complied with the law. No schedule has yet been set for consideration of the lawsuit.

In May 2002, the CPUC approved a servicing order between the Utility and the DWR which sets forth the terms and conditions under which the Utility provides the transmission and distribution of the DWR-purchased electricity; addresses billing, collection and related services performed on behalf of the DWR; and addresses the DWR's compensation to the Utility for providing these services. In October 2002, the DWR filed a proposed amendment to the CPUC's May 2002 servicing order. The DWR's proposed amendment changes the calculation that determines the amount of revenues that the Utility must pass through to the DWR. This proposed amendment would also be used to true up

previous amounts passed through to the DWR as well as future payments. Under its statutory authority, the DWR may request the CPUC to order the utilities to implement such amendments, and the CPUC has approved such amendments in the past without significant change. In December 2002, the CPUC approved an operating order requiring the Utility to perform the operational, dispatch, and administrative functions for the DWR's allocated contracts beginning on January 1, 2003. The operating order, which applies prospectively, includes the DWR's proposed method of calculating the amount of revenues that the Utility must pass through to the DWR. As a result, as of December 31, 2002, the Utility has accrued an additional $369 million (pre-tax) liability for pass-through revenues for electricity provided by the DWR to the Utility's customers in 2001 and 2002.

In December 2002, the CPUC adopted an operating order requiring the Utility to perform the operational, dispatch, and administrative functions for the DWR's allocated contracts beginning on January 1, 2003. (Similar operating orders were also adopted for the other two California IOUs.) The operating order sets forth the terms and conditions under which the Utility will administer the DWR allocated contracts and requires the Utility to dispatch all the generating assets within its portfolio on a least-cost basis for the benefit of the Utility's customers. The order specifies that the DWR will retain legal and financial responsibility for the DWR allocated contracts and that the order does not result in an assignment of the allocated DWR contracts to the Utility.

The CPUC had previously ordered the IOUs to work with the DWR to submit to the CPUC proposed operating agreements governing the DWR allocated contracts. When the operating orders were issued, the DWR and the IOUs had not yet finalized their separate operating agreements. In its decision issuing the operating order, the CPUC noted that if the IOUs and the DWR eventually reach mutual agreement, the CPUC would consider modifying its decision on an expedited basis to terminate the operating orders and approve the operating agreements, assuming that the operating agreements adopted a framework that was substantially similar to the one imposed by the operating orders.

On December 20, 2002, the Utility and the DWR executed an operating agreement following several months of negotiation. The agreement provides that it will not become effective unless approved by the CPUC. The Utility has submitted the agreement to the CPUC for approval and has requested that the CPUC terminate the operating order and approve the operating agreement.

Although the operating order and the operating agreement have fundamentally the same objectives, the operating agreement, among other things:

provides an adequate contractual basis for establishing a limited agency relationship between the Utility and the DWR;

limits the Utility's contractual liability to the DWR and other parties to $5 million per year plus 10 percent of damages in excess of $5 million with a limit of $50 million over the term of the agreement; and

clarifies that the DWR does not intend to review, nor is it responsible for a review of the Utility's least-cost dispatch performance, other than to verify compliance with the supplier contracts.

On December 30, 2002, the Utility filed an application for rehearing of the operating order decision with the CPUC. On January 1, 2003, after having reserved all rights associated with challenges to the operating order, the Utility commenced providing contract administration, scheduling and dispatch services to the DWR under the CPUC's operating order.

DWR Bond Charges. On October 24, 2002, the CPUC approved a decision that, in part, imposes bond charges to recover the DWR's bond costs from most bundled customers effective November 15, 2002, although the decision found that the Utility would not need to increase customers' overall rates to incorporate the bond charge. The DWR bond charge also will be imposed on all direct access

customers, as described above. On December 30, 2002, the CPUC adopted a 2003 bond charge of $0.005 per kWh to start January 6, 2003. The Utility expects to accrue DWR bond-related charges of approximately $340 million during the 12 months ended November 14, 2003. Until the CPUC implements bottoms-up billing (billing for specific rate components) for the Utility, any bond charges will reduce the amount of revenue available to recover previously written-off undercollected purchase power costs and transition costs.

Gas Ratemaking

Natural Gas Distribution

The Utility's 2003 general rate case, or GRC, application requested an increase in natural gas distribution revenue requirements of $105 million over the currently authorized amount of $894 million, to maintain current service levels to existing customers, and to adjust for wages and inflation. The Utility also indicated that it will seek an attrition rate adjustment increase for 2004 and 2005. The attrition rate adjustment mechanism is designed to avoid a reduction in earnings in years between general rate cases to reflect increases in rate base and expenses. The CPUC has ruled that the revenue requirements to be determined in the Utility's 2003 general rate case will be effective January 1, 2003, even though the CPUC will not issue a final decision on the 2003 GRC until after that date. The Utility cannot predict what amount of revenue requirements, if any, the CPUC will authorize for the 2003 through 2005 period, nor when such decision will be made.

Gas distribution costs and balancing account balances are allocated to customers in the Biennial Cost Allocation Proceeding, or BCAP. The BCAP normally occurs every two years and is updated in the interim year for purposes of amortizing any accumulation in the balancing accounts. Balancing accounts for gas distribution and public purpose program revenue requirements accumulate differences between authorized revenue requirements and actual base revenues. In April 2000, the Utility filed its 2000 BCAP application to cover the period January 1, 2000 through December 31, 2002, requesting a decrease in the annual base revenue requirement of $132 million compared to the authorized revenue requirement of $941 million at the time the application was filed. On November 8, 2001, the CPUC issued a decision approving the Utility's BCAP settlement filed in October 2000. The decision adopted a decrease in annual base revenue requirements of $113 million, effective January 1, 2002. The adopted BCAP rates were implemented on January 1, 2002. At the end of 2002, the Utility filed an annual true-up of balancing accounts and other gas transportation rate changes that went into effect January 1, 2003. This filing increased core and noncore transportation rates and revenue requirements by $103 million resulting from the annual true-up, changes authorized in the second year of the BCAP, an increase in the 2002 California Alternate Rates for Energy administration budget, the adopted 2003 cost of capital, an increase in the low income energy efficiency program budget for 2003, the increase in the CPUC reimbursement account fee, and the extension of the Gas Accord.

Natural Gas Transportation and Storage

The Utility's interstate and Canadian natural gas transportation agreements are governed by tariffs which detail rates, rules and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. These tariffs are approved by the FERC in a FERC ratemaking review process and by the Alberta Energy and Utilities Board and the National Energy Board for Canadian tariffs.

Since March 1998, the natural gas transportation and storage services that the Utility has obtained over its owned pipelines have been governed by the rates, terms and conditions approved by the CPUC in the Gas Accord and Gas Accord II settlement agreements through 2003, or, together, the Gas Accord. The Gas Accord separated, or "unbundled," the Utility's natural gas transportation and storage services from its distribution services, changed the terms of service and rate structure for natural gas

transportation and storage services, fixed natural gas transportation and storage rates and allowed core customers to purchase natural gas from competing suppliers.

On January 13, 2003, the Utility filed an amended Gas Accord II application with the CPUC proposing to permanently retain the Gas Accord market structure, and requesting a $55 million increase in the Utility's rates for gas transmission and storage for 2004, or in the case of certain storage provisions from April 1, 2004, to March 31, 2005.

Under the Gas Accord, the Utility is at risk for recovery of its gas transportation and storage costs, and does not have regulatory balancing account protection for over- or undercollections of revenues. Under the Gas Accord, the Utility sells a portion of the transportation and storage capacity at competitive market-based rates. Revenues are sensitive to changes in the weather, natural gas fired generation and price spreads between two delivery or pricing points.

The existing gas transportation and storage rates will continue until the CPUC approves such changes. The Gas Accord II proposal includes rates set based on a demand or throughput forecast basis. In addition it proposes that, at the beginning of the adopted Gas Accord II agreement period, a contract extension and an open season be held for any uncontracted capacity rights. If the Utility were unable to renew or replace existing transportation contracts at the beginning or throughout the Gas Accord II period, or the Utility were to renew or replace those contracts on less favorable terms than adopted by the CPUC, or if overall demand for transportation and storage services were less than adopted by the CPUC in setting rates, the Utility may experience a material reduction in operating revenues. In either case, the Utility's financial condition and results of operations could be adversely affected.

Natural Gas Procurement

The Gas Accord also established the core procurement incentive mechanism, or CPIM, which is used to determine the reasonableness of the Utility's cost of procuring natural gas for the Utility's customers. The Gas Accord II settlement agreement extended the CPIM for one year. Under the CPIM, the Utility's procurement costs are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas prices at the locations where the Utility typically purchases natural gas. If costs fall within a range, or tolerance band currently 99% to 102%, around the benchmark, they are considered reasonable and fully recoverable in customer rates. Ratepayers and shareholders share costs and savings outside the tolerance band.

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

Any awards associated with the CPIM normally are reflected annually in the purchased natural gas balancing account after the close of the CPIM period, which is the 12-month period ending October 31. These awards are not included in earnings until approval by the CPUC. On December 17, 2002, the CPUC's Office of Ratepayer Advocates submitted its report agreeing with the Utility's CPIM performance for the period November 2000 through October 2001. The Utility requested that the CPUC approve a shareholder award of $7.7 million to be effective February 1, 2003. The CPUC has not acted on the Utility's request. In accordance with the Gas Accord, the Utility stopped providing procurement service to noncore customers in March 2001. During the winter of 2000/2001 when there was a steep increase in gas commodity prices, many noncore customers switched to core service in order to receive procurement service from the Utility. In 2002, the Utility filed a request with the CPUC to limit the number of noncore customers that could switch to core service because the Utility was concerned that large increases in its gas supply portfolio demand would raise prices for all other core procurement customers, and obligate the Utility to reinforce its pipeline system to provide core service reliability on a short-term basis to serve this new load. Consistent with rules adopted for southern California gas utilities in 2002, the Utility has requested that electric generation, cogeneration, enhanced oil recovery and refinery customers be prohibited from electing core service and that remaining noncore customers elect core service for a minimum five-year term.

On June 27, 2002, the CPUC opened a proceeding in response to a FERC order authorizing marketers in California to turn back up to 725 million cubic feet per day of firm capacity on the El Paso Pipeline Company, or El Paso, interstate pipeline. The first phase of the proceeding dealt with rules for the major California utilities to obtain El Paso turned-back capacity not subscribed to by other California replacement shippers. On July 17, 2002, the CPUC ordered utilities to obtain such capacity, and stated that if the utilities complied with this order that they would also receive full recovery for costs associated with existing capacity rights on interstate pipelines. The Utility obtained 204 MDth/day of capacity on El Paso in compliance with the CPUC decision. On December 19, 2002, the CPUC found that the Utility had met the objectives, terms and conditions set forth in the CPUC's July 17, 2002 order. The CPUC authorized the Utility to recover all costs associated with the subscription to El Paso pipeline capacity on an equal-cents-per-therm basis from core and noncore customers, subject to reallocation in a later phase of the proceeding. The Utility filed core and noncore transportation rates proposed to be effective March 2003 to recover $47.1 million of annual El Paso costs and costs previously incurred through December 2002. The CPUC also ordered the Utility to continue to treat Transwestern pipeline charges and brokering credits under its core procurement incentive mechanism, or CPIM. The Transwestern costs not currently authorized under the CPIM will be addressed in the second phase of this proceeding. On February 7, 2003, the Utility filed its proposal requesting full recovery of the Transwestern costs and El Paso turned back capacity costs from core customers and inclusion of these costs in its CPIM.

Public Purpose Programs

The Utility continues to administer and/or fund several state-mandated public purpose programs. In December 2002, the CPUC authorized the Utility to fund electric energy efficiency, low-income energy efficiency, research and development, and renewable energy resources programs in the amount of $232 million. The costs will be recovered in electric rates following the rate design phase of the Utility's 2003 general rate case. The CPUC also has authorized the Utility to collect $46 million in gas rates to fund gas energy efficiency, low-income energy efficiency, and research and development programs.

The Utility also provides the California Alternate Rates for Energy, or CARE, low-income discount rate, a rate subsidy paid for by the Utility's other customers, which is currently about $107 million per year.

The CPUC is responsible for authorizing the programs, funding levels, and cost recovery mechanisms for the Utility's operation of both the cost-effective energy efficiency and low-income energy efficiency programs. The CEC administers both the electric public interest research and development program and the renewable energy program on a statewide basis. In 2002, the Utility transferred $99 million to the CEC for these two programs.

Until 2002, the Utility was eligible to receive incentives for administering the energy efficiency program activities. The Utility files an annual earnings claim each year in the annual earnings assessment proceeding, which is the forum for stakeholders to comment on and for the CPUC to evaluate the Utility's claim. Earned incentives can be collected over as long as a 10-year period. In 2002, the CPUC eliminated the opportunity for the IOUs to earn incentives on their 2002 energy efficiency programs, replacing it with a mechanism keeping up to 15% of the energy efficiency expenditures subject to refund if the programs unreasonably miss targets or expenditures are

unreasonably high. The CPUC has also declined to allow the IOUs the opportunity to earn incentives on the 2003 energy efficiency programs. This decision does not affect the mechanism to recover incentives in connection with energy efficiency programs for previous years.

In May 2000, 2001, and 2002, the Utility filed its annual applications claiming incentives totaling to approximately $106 million. In early 2002, the CPUC requested and received briefs on whether the incentive mechanism giving rise to $74 million of the $106 million should be modified to reduce the earnings potential. The CPUC has not yet acted on any of these applications or ruled on the incentive mechanism issue, but has scheduled a prehearing conference to begin the process for addressing the claims.

In October 2002, the CPUC opened a rulemaking to implement the nonbypassable gas public purpose program surcharge mandated by state legislation in 2001. The legislation requires all California gas users, even those users who are not utility customers, to fund public purpose energy efficiency, low-income energy efficiency, research and development, and CARE rate subsidies for qualifying low-income utility customers. The funds are collected by a surcharge on gas consumption, with utilities, many non-utility customers, and interstate pipelines remitting the surcharge revenues to the State Board of Equalization. These funds are allocated to the gas public purpose programs by the CPUC.

The CPUC rulemaking proceeding will formalize the processes for administering the gas consumption surcharge as well as identifying appropriate programs and funding levels for public purpose gas research and development programs.

ELECTRIC UTILITY OPERATIONS

Electric Distribution Operations

The Utility's electric distribution network extends throughout all or a portion of 47 of California's 58 counties, comprising most of northern and central California. The Utility's network consists of approximately 117,955 circuit miles of distribution lines (of which approximately 20% are underground and 80% are overhead) and 730 distribution substations. The Utility's distribution network connects to an electric transmission system at approximately 975 points of contact. This contact between the Utility's distribution network and the transmission system typically occurs at distribution substations where transformers and switching equipment reduce the high-voltage transmission levels at which the electric transmission system transmits electricity, ranging from 60 kilovolts to 500 kilovolts, or kV, to lower voltages, ranging from 4 kV to less than 60 kV, suitable for distribution to customers. The distribution substations serve as the central hubs of the distribution system and consist of transformers, voltage regulation equipment, protective devices and structural equipment. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment which link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution lines or facilities to entities such as municipal and other utilities that then resell the electricity. In certain cases, the distribution system is directly connected to generation facilities.

Electric Distribution Operating Statistics

In 2002, the Utility's electric distribution business delivered a total of approximately 78,230 gigawatt-hours, or GWh, of electricity to approximately 4.8 million electric distribution customers in our service territory, including 21,031 GWh purchased by the DWR and 7,433 GWh provided by direct access service providers.

The following table shows the Utility's operating statistics (excluding subsidiaries) for electric energy sold or delivered, including the classification of sales and revenues by type of service.

	2002	2001	2000	1999	1998
Customers (average for the year):					
Residential	4,171,365	4,165,073	4,071,794	4,017,428	3,962,318
Commercial	483,946	484,430	471,080	474,710	469,136
Industrial	1,249	1,368	1,300	1,151	1,093
Agricultural	78,738	81,375	78,439	85,131	85,429
Public street and highway lighting	24,119	23,913	23,339	20,806	18,351
Other electric utilities	5	5	8		14
Total	4,759,422	4,756,164	4,645,960	4,599,226	4,536,341
Deliveries (in GWh):					
Residential	27,435	26,840	28,753	27,739	26,846
Commercial	31,328	30,780	31,761	30,426	28,839
Industrial(1)	14,729	16,001	16,899	16,722	16,327
Agricultural(1)	4,000	4,093	3,818	3,739	3,069
Public street and highway lighting	674	418	426	437	445
Other electric utilities	64	241	266	167	2,358
California Department of Water Resources Allocation (2001 and 2002 only)	(21,031)	(28,640)			
Total energy delivered(2)	57,199	49,733	81,923	79,230	77,884

	2002	2001	2000	1999	1998
Revenues (in thousands):					
Residential[3]	$ 3,641,582	$ 3,364,466	$ 3,007,675	$ 2,961,788	$ 2,891,424
Commercial[3]	4,468,465	3,925,218	2,693,316	2,837,111	2,793,336
Industrial[3]	1,275,033	1,312,280	509,486	863,951	933,316
Agricultural[3]	531,983	520,855	385,961	391,876	350,445
Public street and highway lighting	73,423	59,875	43,403	49,209	51,195
Other electric utilities	10,028	39,420	26,269	16,501	50,166
Subtotal	10,000,514	9,222,114	6,666,110	7,120,436	7,069,882
California Department of Water Resources pass-through revenues	(2,056,037)	(2,172,666)			
Miscellaneous	193,519	240,276	194,947	162,105	161,156
Regulatory balancing accounts	39,578	36,494	(6,765)	(50,780)	(40,408)
Total electricity operating revenues	$ 8,177,574	$ 7,326,218	$ 6,854,292	$ 7,231,761	$ 7,190,630

	2002	2001	2000	1999	1998
Other Data:					
Average annual residential usage (kWh)	6,577	6,463	7,062	6,905	6,776
Average billed revenues (cents per kWh):					
Residential	13.27	12.50	10.46	10.68	10.77
Commercial	14.26	12.68	8.48	9.32	9.69
Industrial[1]	8.66	7.78	3.02	5.17	5.72
Agricultural[1]	13.30	12.55	10.11	10.48	11.42
Net plant investment per customer ($)	2,105	2,018	1,969	2,388	2,705

(1) The deliveries per kWh and average billed revenues per kWh include electricity provided to direct access customers who procure their own supplies of electricity.

(2) Of the 78,230 GWh the Utility delivered in 2002, 49,766 GWh were procured or generated by the Utility (excluding energy loss and net deliveries to the Western Area Power Administration), 7,433 GWh were procured by direct access service providers and 21,031 GWh were procured by the DWR. Of the 78,373 GWh the Utility delivered in 2001, 45,751 GWh were procured or generated by the Utility (excluding energy loss and net deliveries to the Western Area Power Administration), 3,982 GWh were procured by the Utility's direct access customers and delivered by the Utility and 28,640 GWh were procured by the DWR and delivered by the Utility.

(3) Revenues include direct access revenues, but exclude direct access credits.

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Electric Resources

The Utility's sources of electricity delivered to customers during 2002 were as follows: 11.31% from the Utility's hydroelectric assets, 19.60% from the Utility's nuclear facilities at Diablo Canyon, 1.02% from the Utility's fossil-fuel fired plants, 33.86% from QFs and other power suppliers, and 25.28% from power procured on behalf of customers by the DWR and 8.93% from power procured by direct access service providers.

Retained Generation

At December 31, 2002, the Utility's generation facilities, consisting primarily of hydroelectric and nuclear generating plants, had an aggregate net operating capacity of 6,420 megawatts, or MW. Except as otherwise noted below, at December 31, 2002, the Utility owned and operated the following generating plants, all located in California, listed by energy source:

Generation Type	County Location	Number of Units	Net Operating Capacity kW
Hydroelectric:			
Conventional Plants	16 counties in northern and central California	107	2,684,200
Helms Pumped Storage Plant	Fresno	3	1,212,000
Hydroelectric Subtotal		110	3,896,200
Steam Plants:			
Humboldt Bay	Humboldt	2	105,000
Hunters Point[(1)]	San Francisco	1	163,000
Steam Subtotal		3	268,000
Combustion Turbines:			
Hunters Point[(1)]	San Francisco	1	52,000
Mobile Turbines[(2)]	Humboldt	2	30,000
Combustion Turbines Subtotal		3	82,000
Nuclear:			
Diablo Canyon	San Luis Obispo	2	2,174,000
Total		118	6,420,200

(1) In July 1998, the Utility reached an agreement with the City and County of San Francisco regarding the Hunters Point fossil-fuel fired power plant, which the ISO has designated as a "must-run" facility. The agreement expresses the Utility's intention to retire the plant when it is no longer needed by the ISO.

(2) Listed to show capability; subject to relocation within the system as required.

(3) One mobile turbine (15 MW) is not currently connected to the system. Hunters Point Units 2 and 3 (214 MW) were converted to synchronous condenser operations during 2001.

The Utility is interconnected with electric power systems in the Western Electricity Coordinating Council, which includes 14 western states, Alberta and British Columbia, Canada, and parts of Mexico.

Hydroelectric Generation Assets. The Utility's hydroelectric system consists of 110 generating units at 68 powerhouses, including a pumped storage facility, with a total generating capacity of 3,896 MW. The system includes 99 reservoirs, 76 diversions, 174 dams, 184 miles of canals, 44 miles of flumes, 135 miles of tunnels, 19 miles of pipe, and 5 miles of natural waterways. The system also includes 84 permits and licenses 94 contracts for water rights and 164 statements of water diversion and use.

Diablo Canyon Nuclear Power Plant. Diablo Canyon consists of two nuclear power reactor units, each capable of generating up to approximately 26 million kWh of electricity per day. Diablo Canyon Units 1 and 2 began commercial operation in May 1985 and March 1986, respectively. The operating license expiration dates for Diablo Canyon Units 1 and 2 are September 2021 and April 2025, respectively. As of December 31, 2002, Diablo Canyon Units 1 and 2 had achieved lifetime capacity factors of 82.45% and 85.35%, respectively.

The table below outlines Diablo Canyon's refueling schedule for the next five years. Diablo Canyon refueling outages typically are scheduled every 19 to 21 months. The schedule below assumes that a refueling outage for a unit will last approximately 35 days, depending on the scope of the work required for a particular outage. The schedule is subject to change in the event of unscheduled plant outages.

	2003	**2004**	**2005**	**2006**	**2007**
Unit 1					
Refueling		March	October		April
Startup		April	November		May
Unit 2					
Refueling	February	October		April	
Startup	March	November		May	

The Utility has purchase contracts for, and inventories of, uranium concentrates, uranium hexafluoride, and enriched uranium, as well as one contract for fuel fabrication. Based on current Diablo Canyon operations forecasts and a combination of existing contracts and inventories, the requirements for uranium supply, conversion of uranium to uranium hexafluoride, and the requirement for the enrichment of the uranium hexafluoride to enriched uranium, will be met through 2004. The fuel fabrication contract for the two units will supply their requirements for the next five operating cycles of each unit. In most cases, the Utility's nuclear fuel contracts are requirements-based, with the Utility's obligations linked to the continued operation of Diablo Canyon.

The Utility has insurance coverage for property damage and business interruption losses as a member of Nuclear Electric Insurance Limited, or NEIL. NEIL is a mutual insurer owned by utilities with nuclear generating facilities. Under these insurance policies, if the nuclear generating facility of a member utility suffers a loss due to a prolonged accidental outage, the Utility may be subject to maximum retrospective premium assessments of $25 million with respect to property damage and $8 million with respect to business interruption losses per year if losses exceed the resources of NEIL.

Effective November 15, 2001, in the event that one or more acts of terrorism cause property damage under any of the nuclear insurance policies issued by NEIL within 12 months from the date the first property damage occurs, the maximum recovery under all the nuclear insurance policies will be an aggregate of $3.24 billion, plus the additional amount recovered by NEIL for the losses from reinsurance, indemnity, and any other applicable sources. Under the Terrorism Risk Insurance Act of 2002, NEIL would be entitled to receive substantial reinsurance for an act caused by a foreign terrorist. The Terrorism Risk Insurance Act of 2002 expires on December 31, 2005.

The Price-Anderson Act, as amended by Congress in 1988, limits public liability claims that could arise from a nuclear incident to a maximum of $9.5 billion per incident. The Utility has purchased primary insurance of $300 million for the Diablo Canyon Power Plant for public liability claims resulting from a nuclear incident. The Utility has secondary financial protection that provides an additional $9.2 billion of coverage, as required by the Price-Anderson Act. Under the Price-Anderson Act, secondary financial protection is required for all nuclear electrical generation reactors having a

rated operating capacity of at least 100 MW. There are 105 currently licensed reactors having a rated capacity in excess of 100 MW, including Diablo Canyon's Units 1 and 2. The Price-Anderson Act 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 $300 million, 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. The Utility also has $53.3 million of private liability insurance for Humboldt Bay Power Plant, where the Utility has a shutdown nuclear unit. In addition, the Utility has a $500 million indemnification from the NRC for public liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of private liability insurance for Humboldt Bay Power Plant. The Price-Anderson Act expired on August 1, 2002. By the terms of the act itself, the provisions of the act will remain in effect until Congress renews the act. The current draft of the bill to renew this act would increase the maximum assessment per nuclear incident per unit to $99 million from $88 million, with payments in each year limited to a maximum of $15 million per nuclear incident per unit, increased from $10 million.

Allocation of DWR Electricity to the California Investor-Owned Utilities

Under the authority of AB 1X, the DWR entered into 35 long-term electricity procurement contracts, representing in the aggregate an average annual capacity of 10,780 MW over the next seven years. The California IOUs act as billing and collection agents for the DWR's sales of its electricity to retail customers. The DWR's authority under AB 1X to enter into new electricity procurement arrangements expired on December 31, 2002.

In September 2002, the CPUC issued a decision that allocates the electricity provided through the DWR contracts among the customers of the three California IOUs. The DWR allocation generally consists of electricity quantities under contracts with specified delivery points in the Utility's service territory. The power available under the contracts is to be dispatched in conjunction with the IOU's existing resources on a least-cost basis, with surplus energy sales allocated pro rata between the DWR and the IOU's resources based on their relative amounts of generation. Some of the DWR contracts are firm commitments requiring the DWR to make purchases of specified quantities of electricity, others give the DWR the option as to whether to purchase the quantity of electricity set forth in the contract, and others have a combination of mandatory and optional purchases. Of the 19 DWR contracts allocated to the Utility, 11 involve mandatory purchase commitments, for a total average capacity of 3,010 MW, and the remaining 8 contracts involve optional purchase commitments, for a total average capacity of 1,610 MW.

The September 2002 CPUC decision orders the DWR to allocate its variable costs on a contract-by-contract basis. The allocation of both fixed and variable costs was decided in the annual DWR revenue requirement proceeding described above.

The California IOUs began performing all the day-to-day scheduling, dispatch and administrative functions associated with the DWR contracts allocated to their portfolios on January 1, 2003. The DWR retains legal title to electricity purchased under the allocated contracts as well as financial reporting and payment responsibility associated with these contracts. The IOUs continue to act as billing and collection agents for the DWR.

Although the IOUs will be held to a reasonableness standard in their scheduling and dispatch decision-making and their administration of the DWR contracts, the CPUC has determined that the maximum risk of potential disallowance each IOU should face for all of its procurement activities, including the operation and dispatch of DWR's contracts, should be limited to twice the IOU's annual administrative costs of managing procurement activities. The Utility anticipates that its annual administrative costs of managing procurement activities will be approximately $18 million in 2003. The DWR has stated publicly that it intends to transfer full legal title of, and responsibility for, the DWR

electricity contracts to the IOUs as soon as possible. However, SB 1976 does not contemplate a transfer of title of the DWR contracts to the IOUs. In addition, the operating order issued by the CPUC on December 19, 2002, implementing the Utility's operational and scheduling responsibility with respect to the DWR allocated contracts specifies that the DWR will retain legal and financial responsibility for the contracts and that the December 19, 2002, order does not result in an assignment of the DWR allocated contracts. The Utility's proposed plan of reorganization prohibits the Utility from accepting, directly or indirectly, assignment of legal or financial responsibility for the DWR contracts. There can be no assurance that either the State of California or the CPUC will not seek to provide the DWR with authority to effect such a transfer of legal title in the future. The Utility has informed the CPUC, the DWR and the State that the Utility would vigorously oppose any attempt to transfer the DWR allocated contracts to the Utility without the Utility's consent.

Qualifying Facility Agreements

The Utility is required by CPUC decisions to purchase electric energy and capacity from independent power producers that are qualifying facilities, or QFs, under the Public Utility Regulatory Policies Act of 1978 or PURPA. Pursuant to PURPA, the CPUC required California utilities to enter into a series of QF long-term power purchase agreements and approved the applicable terms, conditions, price options, and eligibility requirements. The agreements 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 or increased if the facility fails to meet or, alternatively, exceeds performance requirements specified in the applicable power purchase agreements.

As of December 31, 2002, the Utility had agreements with 285 QFs for approximately 4,200 MW. The 4,200 MW consist of 2,600 MW from cogeneration projects, 700 MW from wind projects and 900 MW from other projects, including biomass, waste-to-energy, geothermal, solar and hydroelectric. Power purchase agreements for 2,100 MW expire between 2003 and 2015 while agreements for an additional 1,600 MW expire between 2015 and 2028. Power purchase agreements for 500 MW have no specific expiration date and will terminate upon exercise of a termination option by the QF. QF power purchase agreements accounted for approximately 25% of the Utility's 2002 deliveries and no single agreement accounted for more than 5% of its electricity deliveries.

In August 2002, the CPUC ordered the IOUs to offer transitional standard offer no. 1 contracts, or TSO1 contracts, to certain QFs whose power purchase agreements with the IOU had expired or were about to expire. The term of these transitional contracts will end when the IOU fully implements its CPUC-approved long-term procurement plan or on December 31, 2003, whichever occurs first. The Utility signed TSO1 contracts with nine QFs. These new contracts have been approved by the Bankruptcy Court and the CPUC and became effective on January 1, 2003.

Since December 2001, the Bankruptcy Court has approved supplemental agreements between the Utility and most QFs to resolve the applicable interest rate to be applied to pre-petition amounts owed to QFs. The supplemental agreements

- set the interest rate for pre-petition payables at 5%,
- provide for a "catch-up payment" of all accrued and unpaid interest through the initial payment date, and
- depending on the amount owed, either (a) provide for the immediate payment of the principal and interest amount of the pre-petition payables or (b) payment in 12 or 6 equal monthly payments beginning on the last business day of the month during which Bankruptcy Court approval was granted.

If the effective date of the Utility's Plan occurs before the last monthly payment is made, the remaining unpaid principal and unpaid interest would be paid on the effective date. Additionally, since January 2002, the Utility has entered into agreements with additional QFs to assume their power purchase agreements, which agreements also contained the same interest and payment terms contained in the supplemental agreements described above. At December 31, 2002, $901 million in principal and $60 million in interest have been paid to the QFs. Through December 31, 2002, 264 of 313 QFs have signed assumption and/or supplemental agreements. The Utility believes that some of the remaining QFs also will wish to enter into similar supplemental agreements.

Renewable Resource Energy Contracts

An August 22, 2002, the CPUC issued a decision requiring the California IOUs to contract for electricity from renewable resources for an additional 1% each year beginning January 1, 2003, until a 20% renewable resource portfolio is achieved by no later than 2017. Interim renewable resources contracts should range from 5 to 15 year terms. In addition, the CPUC decision determined that any renewable resources contract prices that meet or are less than a provisional benchmark of 5.37 cents per kWh will be deemed reasonable, although prices above the benchmark also may be pre-approved for cost recovery through the pre-approval process adopted in the decision. The Utility currently estimates that the annual 1% increase in renewable resource electricity in its portfolio will initially require between 80 and 100 MW of additional renewable capacity to be added per year. On September 16, 2002, the Utility issued a request for offers to meet the 1% annual renewable resource requirement and on November 15, 2002, the Utility submitted the offers selected to the CPUC for approval. These submissions, which the CPUC approved in December 2002, will meet the Utility's renewable resource requirement for 2003.

Other Third-Party Power Agreements

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. Costs associated with these contracts to purchase power are eligible for recovery by the Utility as transition costs through the collection of the non-bypassable competition transition charge. At December 31, 2002, the undiscounted future minimum payments under these contracts are approximately $32.9 million for each of the years 2003 and 2004 and a total of $247 million for periods thereafter. Irrigation district and water agency deliveries in the aggregate accounted for approximately 4.24% of the Utility's 2002 electric power requirements.

The Utility also has two power purchase agreements representing an aggregate of 450 MW, both of which expire at the end of 2003. The Utility's minimum payments due under these contracts are $196 million for 2003.

The amount of electric power received and the total payments made under QF, irrigation district, water agency, and bilateral agreements are as follows:

	2002	2001	2000	1999	1998
Gigawatt-hours received	28,088	23,732	26,027	25,910	25,994
Energy payments (in millions)	$ 1,051	$ 1,454	$ 1,549	$ 837	$ 943
Capacity payments (in millions)	$ 506	$ 473	$ 519	$ 539	$ 529
Irrigation district and water agency payments (in millions)	$ 57	$ 54	$ 56	$ 60	$ 53
Bilateral contract payments	$ 196	$ 155	$ 53		

Western Area Power Administration. In 1967, the Utility and the Western Area Power Administration, or WAPA, entered into a long-term power contract governing (1) the interconnection of the Utility's and WAPA's transmission systems, (2) WAPA's use of the Utility's transmission and distribution system, and (3) the integration of the Utility's and WAPA's loads and resources. The contract gave the Utility access to surplus hydroelectric generation and obligates the Utility to provide WAPA with electricity when its own resources are not sufficient to meet its requirements. The contract terminates on December 31, 2004.

As a result of California's electric industry restructuring in 1998, the Utility was required to procure the electric power that 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 of energy to WAPA. The cost to fulfill the Utility's obligations to WAPA under the contract is uncertain. However, the Utility expects that the cost of meeting its obligation to WAPA will be greater than the price that the Utility receives from WAPA under the contract. In part, the amount of electricity the Utility will be required to deliver to WAPA depends on the amount of electricity available from WAPA's hydroelectric resources. Under AB 1890, the Utility's retail ratepayers pay for this difference as a stranded 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 at this time 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's net amount purchased from the Utility was 3,619 GWh in 2002, 4,823 GWh in 2001, and 5,120 GWh in 2000.

Electric Transmission

To transmit electricity to load centers, the Utility, at December 31, 2002, owned approximately 18,605 circuit miles of interconnected transmission lines operated at voltages of 60 kV to 500 kV and transmission substations having a capacity of approximately 47,596 megavolt-amperes (MVA), including spares, and excluding power plant interconnection facilities. Electricity is distributed to customers through approximately 118,033 circuit miles of distribution system and distribution substations having a capacity of approximately 24,020 MVA. For the year ended December 31, 2002, the Utility sold 104,499,158 MWh to its bundled retail customers and transmitted 7,433,238 MWh to direct access customers.

In connection with electric industry restructuring, in 1998 the IOUs relinquished to the ISO control, but not ownership, of their transmission facilities. The FERC has jurisdiction over the transmission facilities, and revenue requirements and rates for transmission service are set by the FERC. The ISO commenced operations on March 31, 1998. The ISO, regulated by the FERC, controls the operation of the transmission system and provides open access transmission service on a nondiscriminatory basis. As control area operator, the ISO also is responsible for assuring the reliability of the transmission system.

In 1998, the FERC approved the forms of agreements for Reliability Must-Run, or RMR, service that have been entered into between RMR facility owners and the ISO to ensure grid reliability and avoid the exercise of local market power. The costs of RMR contracts attributed to supporting the Utility's historic transmission control area are charged to the Utility as a Participating Transmission Owner, or PTO. These costs, which were approximately $311 million in 2002, are currently recovered from the Utility's retail customers and, subject to FERC filings to be made by March 31, 2003, wholesale transmission customers.

In March 2000, the ISO filed an application with the FERC seeking to establish its own Transmission Access Charge (TAC) as directed in AB 1890. The FERC accepted the ISO's TAC filing, subject to refund, but suspended the proceeding to allow interested parties to enter into settlement discussions. After settlement discussions proved unsuccessful, in December 2002 FERC set the case for hearing. In late December 2000, the ISO made a further implementation filing, also accepted by the FERC subject to refund, to establish specific TAC rates which was triggered by a transmission-owning municipality's application to become a new PTO. The ISO's TAC methodology provides for transition to a uniform statewide high voltage transmission rate, based on the revenue requirements of all PTOs associated with facilities operated at 200 kV and above. The TAC methodology also requires the IOUs, such as the Utility, to pay during a ten-year transition period a charge based on certain costs incurred by new PTOs resulting from joining the ISO and the cost differential from these higher-cost systems being included in the ISO controlled transmission grid. The Utility's obligation for this cost shift is proposed to be capped at $32 million per year.

The Utility has been working closely with the ISO to continue expanding the capacity on the Utility's electric transmission system. One segment of the transmission system proposed to be addressed by the Utility are the transmission facilities known as Path 15, which is located in the southern portion of the Utility's service area, and serves as part of the primary transmission path between northern California and southern California. At times, the current facilities cannot accommodate all low-cost power intended to be transmitted between southern California and northern California. (For transmission purposes, the Diablo Canyon Nuclear Power Plant is located south of Path 15.) This transmission constraint historically has resulted in significant wholesale power price differentials between northern and southern California, with relatively high power prices in northern California and relatively low power prices in southern California.

Following an analysis of the economic benefits of relieving transmission system constraints performed by the ISO, the Utility agreed to participate in a project sponsored by WAPA to upgrade the transfer capability of Path 15. The project entails construction of a new 84 mile, 500 kV transmission line by WAPA between two of the Utility's existing substations. The Utility has agreed to interconnect WAPA's new 500 kV line at the Utility's substations by installing necessary substation equipment and to modify other portions of its transmission system. WAPA will own and operate the new 500 kV line with financing provided by Trans-Elect, Inc., an independent electric transmission company. All participants in the WAPA-sponsored project have agreed to turn over operational control of the transmission system upgrade to the ISO upon completion of the project. In January 2002, the Utility received Bankruptcy Court approval to participate in the WAPA project including spending up to $75 million under its current five-year plan for the substation and system modifications necessary to interconnect to WAPA's new line. In May 2002, the FERC approved a letter agreement between the participants outlining ownership, financing and cost recovery associated with the project. The Utility is in the process of negotiating additional agreements with the project participants to develop schedules and coordinate construction of the project and for the coordinated operation and interconnection of the project with its existing facilities. The Utility's expenditure commitment is contingent upon WAPA meeting construction milestones.

The Utility's investment in its transmission system has been growing substantially over the past several years. The Utility made an additional capital investment of approximately $374 million in its transmission system in 2002 and plans to make an additional capital investment of approximately $504 million in 2003. Through the ISO's Long-Term Grid Planning Process, the Utility files annually with the ISO its transmission system upgrade and expansion plans and provides the ISO and other interested parties the opportunity to review and modify the Utility's planned upgrades and expansions.

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GAS UTILITY OPERATIONS

The Utility owns and operates an integrated gas transmission, storage, and distribution system in California that extends throughout all or a portion of 38 of California's 58 counties and includes most of northern and central California. In 2002, the Utility served approximately 3.9 million natural gas distribution customers.

At December 31, 2002, the Utility's system consisted of approximately 6,300 miles of transmission pipelines, three gas storage facilities, and approximately 38,944 miles of gas distribution lines. The Utility's Line 400/401 interconnects with PG&E GTN's natural gas transmission system. The PG&E GTN pipeline begins at the border of British Columbia, Canada and Idaho, and extends through northern Idaho, southeastern Washington, and central Oregon, and ends on the Oregon-California border where it connects with the Utility's Line 400/401. The Utility's Line 400/401 has a capacity at the border of approximately 2 billion cubic feet, or Bcf. The Utility's Line 300, which connects to the U.S. Southwest pipeline systems (Transwestern, El Paso, Questar, and Kern River) owned by third parties has a capacity at the California/Arizona border of 1,140 MMcf per day. The Utility's underground gas storage facilities located at McDonald Island, Los Medanos, and Pleasant Creek, have a total working gas capacity of 100 Bcf.

Through the interconnection with other interstate pipelines, the Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the southwestern United States, and the Rocky Mountains, as well as natural gas fields in California.

Since 1991, the CPUC has divided the Utility's natural gas customers into two categories core and noncore customers. This classification is based largely on a customer's annual natural gas usage. The core customer class is comprised mainly of residential and smaller commercial natural gas customers. The noncore customer class is comprised of industrial and larger commercial natural gas customers. In 2002, core customers represented over 99% of the Utility's total customers and 41% of its total natural gas deliveries while noncore customer comprised less than 1% of its total customers and 59% of its total natural gas deliveries.

The Utility provides natural gas delivery services to all its core and noncore customers. Core customers can purchase gas from third-party suppliers or can elect to have the Utility provide both delivery service and natural gas supply. Where the Utility provides both supply and delivery, the Utility refers to the service as "bundled service." The Utility offers transmission, distribution, and storage services as separate and distinct services to its non-core customers. These customers have the opportunity to select from a menu of services offered by the Utility and to pay only for the services that they use. Access to the transmission system is possible for all gas marketers and shippers, as well as non-core end-users. The Utility's core customers can select the commodity gas supplier of their choice, but the Utility continues to purchase gas as a regulated supplier for those core customers who do not select another supplier. Currently, over 99% of core customers, representing over 97% of core market demand, choose to receive bundled services from the Utility. The Utility ended its core subscription service in March 2001.

The Utility earns a return on its investment in natural gas distribution facilities. Customers pay a volumetric distribution rate that reflects the Utility's costs to serve each customer class. The Utility has regulatory balancing accounts for core customers designed so that the Utility's results of operations over the long term are not affected by their consumption levels. Results of operations can, however, be affected by noncore consumption levels because there are no similar regulatory balancing accounts related to noncore customers. Approximately 97% of the Utility's natural gas base revenues are recovered from core customers and 3% are recovered from noncore customers. The Utility Gas Accord II application for 2004 requests 100% balancing account treatment for noncore gas distribution revenues.

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The Utility's peak day send-out of natural gas on its integrated system in California during the year ended December 31, 2002 was 4,077MMcf. The total volume of natural gas throughput during 2002 was approximately 749,981 MMcf, of which 733,585 MMcf was sold or transported to direct end-use or resale customers, 15,298 MMcf was used by the Utility primarily for its fossil-fuel fired electric generating plants, and 1,098 MMcf was transported off-system as customer-owned natural gas.

The California Gas Report, which presents the outlook for natural gas requirements and supplies for California over a long-term planning horizon, is prepared annually by the California electric and gas utilities. A comprehensive biennial report is prepared in even-numbered years. A supplemental report is prepared in intervening odd-numbered years updating recorded data for the previous year. The 2002 California Gas Report updated the Utility's annual gas requirements forecast for the years 2002 through 2022, forecasting average annual growth in gas throughput served by the Utility of approximately 1.8%. The gas requirements forecast is subject to many uncertainties and there are many factors that can influence the demand for natural gas, including weather conditions, level of economic activity, conservation, and amount and location of electric generation. The 2003 report is due to be filed July 1, 2003, and will include recorded data for 2002.

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Gas Operating Statistics

The following table shows Pacific Gas and Electric Company's operating statistics (excluding subsidiaries) for gas, including the classification of sales and revenues by type of service:

	2002	2001	2000	1999	1998
Customers (average for the year):					
Residential	3,738,524	3,705,141	3,642,266	3,593,355	3,536,089
Commercial	206,953	205,681	203,355	203,342	200,620
Industrial	1,819	1,764	1,719	1,625	1,610
Other gas utilities	5	6	6	4	5
Total	3,947,301	3,912,592	3,847,346	3,798,326	3,738,324

	2002	2001	2000	1999	1998
Gas supply thousand cubic feet (Mcf) (in thousands):					
Purchased from suppliers in:					
Canada	210,716	209,630	216,684	230,808	298,125
California	19,533	10,425	32,167	18,956	17,724
Other states	67,878	76,589	75,834	107,226	122,342
Total purchased	298,127	296,644	324,685	356,990	438,191
Net (to storage) from storage	(218)	(27,027)	19,420	(980)	(14,468)
Total	297,909	269,617	344,105	356,010	423,723
Pacific Gas and Electric Company use, losses, etc.(1)	16,394	(939)	62,960	47,152	129,305
Net gas for sales	281,515	270,556	281,145	308,858	294,418
Bundled gas sales Mcf (in thousands):					
Residential	202,141	197,184	210,515	233,482	223,706
Commercial	78,812	72,528	66,443	70,093	66,082
Industrial	563	831	4,146	5,255	4,616
Other gas utilities	0	13	41	28	14
Total	281,516	270,556	281,145	308,858	294,418
Transportation only Mcf (in thousands):					
Vintage system (Substantially all Industrial)(2)	508,090	646,079	606,152	484,218	396,872
Revenues (in thousands):					
Bundled gas sales:					
Residential	$ 1,379,036	$ 2,307,677	$ 1,680,745	$ 1,542,705	$ 1,414,313
Commercial	499,214	783,080	513,080	448,655	426,299
Industrial	2,447	15,904	35,347	24,638	24,634
Other gas utilities	829	2	0	77	1,072
Bundled gas revenues	1,881,526	3,106,663	2,229,172	2,016,075	1,866,318
Transportation only revenue:					
Vintage system (Substantially all Industrial)	$ 308,212	$ 365,550	$ 324,319	$ 267,544	$ 232,038
PG&E Expansion (Line 401)	8,275	9,380	13,392	19,091	42,194
Transportation service only revenue	316,487	374,930	337,711	286,635	274,232
Miscellaneous	126,415	(92,531)	84,526	(47,311)	41,364
Regulatory balancing accounts	11,431	(253,476)	131,762	(259,648)	(448,351)
Operating revenues	$ 2,335,859	$ 3,135,586	$ 2,783,171	$ 1,995,751	$ 1,733,563

(1) Includes fuel for Pacific Gas and Electric Company's fossil-fuel fired generating plants.

(2) Does not include on-system transportation volumes transported on the PG&E Expansion of 382 MMcf, 259 MMcf, 4,833 MMcf, 1,251 MMcf, and 34,169 MMcf for 2002, 2001, 2000, 1999, and 1998, respectively.

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	2002	2001	2000	1999	1998
Selected Statistics:					
Average annual residential usage (Mcf)	54.1	53.2	59	65	63
Heating temperature % of normal[1]	104.6	105.1	101.2	108.5	93.0
Average billed bundled gas sales revenues per Mcf:					
Residential	$ 6.82	$ 11.70	$ 7.98	$ 6.61	$ 6.32
Commercial	6.33	10.80	7.72	6.40	6.45
Industrial	4.35	19.15	8.53	4.69	5.36
Average billed transportation only revenue per Mcf:					
Vintage system	0.61	0.56	0.54	0.66	0.66
PG&E Expansion (Line 401)	7.54	1.78	2.04	0.53	0.54
Net plant investment per customer[2]	$ 1,006	$ 970	$ 1,003	$ 1,011	$ 1,040

(1) Over 100% indicates colder than normal.

Natural Gas Supplies

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States. The composition of the Utility's portfolio of natural gas procurement contracts has fluctuated, generally based on market conditions. The Utility's CPUC-approved core procurement incentive mechanism, or CPIM, uses published monthly and daily natural gas prices for determining the Utility's benchmark price. During the year ended December 31, 2002, the Utility purchased approximately 298,127 Mcf of natural gas from approximately 54 suppliers. Substantially all this supply was purchased under contracts with a term of less than one year. The Utility's largest individual supplier represented approximately 9.4% of the Utility's total natural gas purchases during the year ended December 31, 2002.

Approximately 70% of the Utility's natural gas supplies come from western Canada. The Utility has firm transportation agreements for western Canadian natural gas with TransCanada NOVA Gas Transmission, Ltd. and TransCanada PipeLines Ltd., B.C. System. These systems transport the natural gas to the U.S. and Canadian border, where it enters the transportation pipeline of PG&E GTN near Kingsgate, British Columbia. Approximately 28% of the Utility's natural gas supplies come from the southwestern United States and the Rocky Mountains. The Utility has firm transportation agreements with Transwestern Pipeline Company and El Paso Natural Gas Company to transport this natural gas to interconnections with the Utility's gas transportation and storage system near Topock, Arizona.

The following table shows the total volume and average price of gas in dollars per thousand cubic feet (Mcf) purchased by the Utility from these sources during each of the last five years.

	2002		2001		2000		1999		1998	
	Thousands of Mcf	Avg. Price[1]	Thousands of Mcf	Avg. Price[1]	Thousands of Mcf	Avg. Price[1]	Thousands of Mcf	Avg. Price[1]	Thousands of Mcf	Avg. Price[1]
Canada	210,716	$ 2.42	209,630	$ 4.43	216,684	$ 4.05	230,808	$ 2.50	298,125	$ 2.00
California	19,533	2.88	10,425	16.68	32,167	8.20	18,956	2.45	17,724	2.44
Other states (substantially all U.S. Southwest)	67,878	3.04	76,588	10.41	75,835	5.99	107,227	2.42	122,342	2.62

	2002		2001		2000		1999		1998	
Total/Weighted Average	298,127	$ 2.59	296,643	$ 6.40	324,686	$ 4.92	356,991	$ 2.47	438,191	$ 2.19

(1) The average prices for Canadian and U.S. Southwest gas include the commodity gas prices, interstate pipeline demand or reservation charges, transportation charges, and other pipeline assessments, including direct bills allocated over the quantities received at the California border. Beginning March 1, 1998, the average price for gas also includes intrastate pipeline demand and reservation charges. These costs previously were bundled in gas rates.

Under the CPIM, the Utility's procurement costs are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas prices at the locations where the Utility typically purchases natural gas. If costs fall within a range, or tolerance band, currently between 99% to 102%, around the benchmark, they are considered reasonable and the Utility may fully recover them in customer rates. Ratepayers and shareholders share costs and savings outside the tolerance band.

Natural Gas Gathering Facilities

The Utility's natural gas gathering system collects and processes natural gas from third-party wells in California. The natural gas is processed to remove various impurities from the natural gas stream and to odorize the natural gas so that it may be detected in the event of a leak. The facilities include approximately 510 miles of gas gathering pipelines as well as dehydration, separation, regulation, odorization and metering equipment located at approximately 60 stations. The natural gas gathering system is geographically dispersed and is located in 16 California counties. Approximately 190 MMcf per day of natural gas flows through the Utility's gas gathering system.

Natural Gas Transportation and Storage Services Agreements

Since March 1998, the Utility's natural gas transportation and storage services have been governed by the rates, terms, and conditions approved by the CPUC in the Gas Accord. The Gas Accord separated, or "unbundled," the Utility's natural gas transportation and storage services from its distribution services, changed the terms of service and rate structure for natural gas transportation and storage services, and fixed natural gas transportation and storage rates. As required by the CPUC, in October 2001, the Utility filed an application with the CPUC requesting a two-year extension, without modification, of the Gas Accord. In August 2002, the CPUC approved a settlement agreement among the Utility and other parties that provided for a one-year extension of the Gas Accord. The Gas Accord II settlement left unresolved the issues raised in the application insofar as they relate to the second year of the two-year application.

Following the CPUC administrative law judge's rulings which required the Utility to also file a cost and rate proposal for 2004, the Utility filed an amended application, on January 13, 2003, which proposes, among other things, retention of the basic Gas Accord market structure, transmission and storage costs and rates for 2004, a 13.4% equity return for gas transmission and storage assets, a 1-in-10 reliability standard, and for the Utility to remain at risk for recovery of all transmission and storage facility costs. Testimony by interested parties is due by February 28, 2003, and rebuttal testimony by March 24, 2003, with hearings to begin on April 1, 2003.

The Utility has a number of arrangements for natural gas transportation services. These agreements include provisions for payment of fixed demand charges for reserving firm pipeline capacity as well as volumetric transportation charges. The total demand charges may change periodically as a result of changes in regulated tariff rates. Additionally, the forward market value for the firm capacity is subject to change. The Utility held hedge agreements for a portion of this forward value at the time it defaulted in April 2001, which caused the hedge counterparties to terminate their agreements and demand termination payments. The Utility recognized a total of $111 million in losses related to these terminated agreements in 2001. The combined charges the Utility incurred under the transportation agreements and hedge agreements, including losses on terminated contracts, were $101 million, $239 million, and $94 million in 2002, 2001, and 2000, respectively. These amounts include payments that the Utility made to PG&E GTN of $47 million, $40 million, $46 million in 2002, 2001, and 2000, respectively, which are eliminated in the consolidated financial statements of PG&E Corporation.

Under a firm transportation agreement with PG&E GTN that runs through October 31, 2005, the Utility currently retains capacity of approximately 610 MDth/d on the PG&E GTN system to support its core customers. The Utility has been able to broker its unused capacity on PG&E GTN's system, when not needed for core customers.

Pursuant to the CPUC's order requiring the utilities to subscribe for capacity on El Paso's pipeline, the Utility has obtained 204 MDth/day of El Paso capacity rights on interstate pipeline under three natural gas transportation agreements commencing on November 1, 2002. The costs are currently allocated to core and noncore customers subject to reallocation in a future CPUC proceeding.

The Utility may recover demand charges through the CPIM and through brokering activities.

The Utility may, upon prior notice, extend each of these natural gas transportation contracts for additional minimum terms ranging, depending on the particular contract, from 1 to 10 years with demand charges to be set by tariffs approved by Canadian regulators in the case of TransCanada NOVA Gas Transmission, Ltd. and TransCanada PipeLines Ltd., B.C. System and the FERC in all other cases. For the contracts under FERC jurisdiction, the Utility has a right of first refusal allowing the Utility to renew pipeline service agreements at the end of their terms. If another prospective shipper wants the capacity, the Utility would be required to match the competing bid with respect to both price and term. In the past, FERC policy required only that the existing shipper match the price and a term of up to five years. In a recent order on remand from an appellate court, the FERC removed the five-year cap on matching bids. Under the new FERC policy, the existing shipper must match the competing bid with respect to both price and term, with no limit on the number of years that the shipper's bid must match.

PG&E NATIONAL ENERGY GROUP, INC.

PG&E NEG is currently focused on power generation and natural gas transmission in the United States. PG&E NEG reports its business segments as follows: interstate pipeline operations (or "Pipeline Business") and power generation also referenced as Integrated Energy and Marketing (or "Generation Business").

Generation Business

In the Generation Business segment, PG&E NEG engages in the generation of electricity in the continental United States. As of December 31, 2002, PG&E NEG had ownership or leasehold interests in 16 operating generating facilities with a net generating capacity of 1,476 megawatts (MW), as follows:

Number of Facilities	Net MW	Primary Fuel Type	% of Portfolio
8	667	Coal/Oil	45
7	797	Natural Gas	54
1	12	Wind	1
16	1,476		100

PG&E NEG provides operating and/or management services for 14 of these 16 owned and leased generating facilities. Plant operations are focused on maximizing the availability of a facility to generate power during peak energy price hours, improving operating efficiencies and minimizing operating costs while placing a heavy emphasis on safety standards, environmental compliance and plant flexibility. These generating facilities sell all or a majority of their electrical capacity and output to one or more third parties under long-term power purchase agreements tied directly to the output of that plant.

PG&E NEG holds interests in these projects through wholly owned indirect subsidiaries and typically manages and operates these facilities through an operation and maintenance agreement and/or a management services agreement. These agreements generally provide for management, operations,

maintenance and administration for day-to-day activities, including financial management, billing, accounting, public relations, contracts, reporting and budgets. In order to provide fuel for PG&E NEG's independent power projects (IPPs), natural gas and coal supply commitments are typically purchased from third parties under long-term supply agreements.

The revenues generated from long-term power sales agreements usually consist of two components: energy payments and capacity payments. Energy payments are typically based on the facility's actual electrical output and capacity payments are based on the facility's total available capacity. Energy payments are made for each kilowatt-hour of energy delivered, while capacity payments, under most circumstances, are made whether or not any electricity is delivered. However, capacity payments may be reduced if the facility does not attain an agreed availability level. The average life of the power sales agreements is 15 years.

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Description of Generating Facilities

The following table provides information regarding each of PG&E NEG's owned or leased generating facilities, as of December 31, 2002, excluding assets to be abandoned and assets held for sale or use, such as the USGenNE facilities, Lake Road, La Paloma, Attala, and the GenHoldings projects:

Generating Facility	State	Total MW(1)	Net Interest in Total MW(2)	Structure	Fuel	Primary Output Sales Method	Date of Commercial Operation	Contract Expiration
New England Region								
MASSPOWER	MA	267	35	Owned	Natural Gas	Power Purchase Agreements	1993	2008 & 2013
Pittsfield	MA	173	154	Leased	Natural Gas	Power Purchase Agreements	1990	2010
Subtotal		440	189					
Mid-Atlantic and New York Region								
Selkirk	NY	345	145	Owned	Natural Gas	Power Purchase Agreements and Competitive Market	1992	2008/2014
Carneys Point	NJ	245	123	Owned	Coal	Power Purchase Agreements	1994	2024
Logan	NJ	225	113	Owned	Coal	Power Purchase Agreement	1994	2024
Northampton	PA	110	55	Owned	Waste Coal	Power Purchase Agreements	1995	2020
Panther Creek	PA	80	44	Owned	Waste Coal	Power Purchase Agreement	1992	2012
Scrubgrass	PA	87	44	Owned	Waste Coal	Power Purchase Agreement	1993	2017
Madison	NY	12	12	Owned	Wind	Competitive Market	2000	N/A
Subtotal		1,104	536					
Midwest Region								
Ohio Peakers	OH	149	149	Owned	Natural Gas	Competitive Market	2001	2005
Southern Region								
Indiantown	FL	330	116	Owned	Coal	Power Purchase Agreement	1995	2025
Cedar Bay	FL	258	165	Owned	Coal	Power Purchase Agreement	1994	2024
Subtotal		588	281					
Western Region								
Hermiston	OR	474	119	Owned	Natural Gas	Power Purchase Agreement	1996	2016
Colstrip	MT	40	7	Owned	Waste Coal	Power Purchase Agreement	1990	2025
San Diego Peakers	CA	84	84	Owned	Natural Gas	Competitive Market	2001	2003
Plains End	CO	111	111	Owned	Natural Gas	Power Purchase Agreement	2002	2012
Subtotal		709	321					

Generating Facility	State	Total MW(1)	Net Interest in Total MW(2)	Structure	Fuel	Primary Output Sales Method	Date of Commercial Operation	Contract Expiration
Total		2,990	1,476					

(1) Megawatts are based on winter output.

(2) PG&E NEG's net interest in the total MW of an independent power project is the current percentage ownership or leasehold interest in the project affiliate and does not necessarily correspond to PG&E NEG's percentage of the project's expected cash flow.

Natural Gas Transmission Business

In its Pipeline Business segment, PG&E NEG owns, operates and develops natural gas pipeline facilities, including the pipeline owned by PG&E GTN, an interest in the Iroquois Gas Transmission System, and the North Baja pipeline.

The following table summarizes PG&E NEG's gas transmission pipelines:

Pipeline Name	Location	In Service Date	Approx. Capacity (MMcf/d)	2001 Load Factor	Length (miles)	Ownership Interest
PG&E GTN	ID, OR, WA	1961	2,900	91%	1,356	100.0%
Iroquois Gas Transmission System	NY, CT	1991	850	88%	375	5.2%
North Baja	AZ, CA	2002/2003	500	N/A	80	100.0%

PG&E GTN Pipeline System. The PG&E GTN pipeline consists of over 1,350 miles of natural gas transmission pipeline in the Pacific Northwest with a capacity of approximately 2.9 billion cubic feet of natural gas per day. This pipeline begins at the British Columbia-Idaho border, extends for approximately 612 miles through northern Idaho, southeastern Washington and central Oregon, and ends at the Oregon-California border, where it connects with other pipelines. The PG&E GTN pipeline commenced commercial operation in 1961 and has subsequently expanded various times through 2002. This pipeline is the largest transporter of Canadian natural gas into the United States. The mainline system of this pipeline is composed of two parallel pipelines (along with 21 miles of a third parallel line) with 13 compressor stations totaling approximately 513,400 horsepower and ancillary facilities which include metering and regulating facilities and a communication system. PG&E GTN has approximately 639 miles of 36-inch diameter gas transmission lines (612 miles of 36-inch diameter pipe and 27 miles of 36-inch diameter pipeline looping) and approximately 611 miles of 42-inch diameter pipe. The PG&E GTN system also includes two laterals off of its mainline system, the Coyote Springs Extension, which supplies natural gas to an electric generation facility owned by Portland General Electric Company and other customers, and the Medford Extension, which supplies natural gas to Avista Utilities and Pacificorp Power Marketing. The Coyote Springs Extension is composed of approximately 18 miles of 12-inch diameter pipe, originating at a point on the PG&E GTN mainline system approximately 27 miles south of Stanfield, Oregon and connecting to Portland General Electric's electric generation facility near Boardman, Oregon. The Medford Extension consists of approximately 22 miles of 16-inch diameter pipe and 66 miles of 12-inch diameter pipe and extends from a point on the PG&E GTN mainline system near Bonanza, in Southern Oregon, to interconnection points with Avista Utilities at Klamath Falls and Medford, Oregon.

PG&E GTN Interconnection With Other Pipelines. PG&E GTN's pipeline facilities interconnect with facilities owned by TransCanada PipeLines Ltd.'s B.C. System (TransCanada) and facilities owned by Foothills Pipe Lines South B.C. Ltd. (Foothills South B.C.) near the Idaho-British Columbia border. PG&E GTN's pipeline facilities also interconnect with the facilities owned by the Utility, at the Oregon-California border, with the facilities owned by Northwest Pipeline Corporation (Northwest Pipeline) in Northern Oregon and in Eastern Washington, and with the facilities owned by Tuscarora Gas Transmission Company (Tuscarora) in Southern Oregon. PG&E GTN also delivers gas along various mainline delivery points to two local gas distribution companies.

TransCanada PipeLines Ltd. and Foothills South B.C. Ltd. PG&E GTN's pipeline facilities interconnect with the facilities of TransCanada and Foothills South B.C. near Kingsgate, British Columbia. Through the TransCanada and Foothills South B.C. systems, PG&E GTN's customers have access to natural gas from the Western Canadian Sedimentary Basin. TransCanada's Alberta System delivers gas from production areas to provincial gas distribution utilities and to all provincial export points, including the interconnect at the Alberta-British Columbia border to TransCanada's B.C. System and Foothills South B.C. for delivery south into PG&E GTN's system at the British Columbia-Idaho border.

Northwest Pipeline Corporation. PG&E GTN's pipeline facilities interconnect with the facilities of Northwest Pipeline near Spokane and Palouse, Washington and near Stanfield and Klamath Falls,

Oregon. Northwest Pipeline is an interstate natural gas pipeline which both delivers gas to and receives gas from PG&E GTN and competes with PG&E GTN for transportation of natural gas into the Pacific Northwest and California. Northwest Pipeline's gas transportation services are regulated by the FERC.

Tuscarora Gas Transmission Company. PG&E GTN's pipeline facilities interconnect with the facilities of Tuscarora near Malin, Oregon. Tuscarora is an interstate natural gas pipeline that transports natural gas from this interconnection to the Reno, Nevada area. Tuscarora's gas transportation services are regulated by the FERC.

Pacific Gas and Electric Company. PG&E GTN's pipeline interconnects with the Utility's gas transmission pipeline system at the Oregon-California border. The Utility's pipeline facilities deliver natural gas to customers in Northern and Central California and interconnect with other pipeline facilities at the California-Arizona border near Topock, Arizona. The Utility's gas transmission system is currently regulated by the CPUC. In April 2001, the Utility commenced a case under Chapter 11 of the U.S. Bankruptcy Code. As part of the Utility's proposed plan of reorganization, in November 2001, the Utility filed an application with the FERC requesting authorization to operate these facilities as a federally-regulated interstate pipeline system. In conjunction with that application, PG&E GTN filed an application with the FERC for authorization to abandon by sale to the Utility approximately 2.66 miles of 42-inch and 36-inch mainline pipe from the southernmost meter station in Oregon to the California border. The transaction implementing this abandonment closed into escrow on November 14, 2002, pending receipt of satisfactory authorizations from the FERC and the Bankruptcy Court.

PG&E GTN's Expansion Projects. PG&E GTN has completed its 2002 Expansion Project, expanding its system by approximately 217 million cubic feet (MMcf) per day. Approximately 40 MMcf per day of that expansion capacity was placed in service in November 2001 and the remaining capacity was placed in service in November 2002. The total cost of the expansion is approximately $127 million. One shipper, contractually committed to 175,000 decatherm (Dth) per day of capacity on this project, failed to provide PG&E GTN with adequate assurances of the shipper's ability to meet its obligations under its transportation contract. On October 25, 2002, PG&E GTN and that shipper terminated the transportation contract and PG&E GTN received $16.8 million from that shipper in settlement of the contract.

In response to changing market conditions, PG&E GTN reached agreement with all shippers contractually committed on a second expansion (2003 Expansion Project) to terminate their firm transportation precedent agreements. Accordingly, on October 10, 2002, PG&E GTN filed with the FERC a request to vacate its 2003 Expansion Project proceeding and deferred the project. To date, PG&E GTN has spent $5.4 million on the project. PG&E GTN is continuing necessary development activities and expects to refile an application with FERC when market conditions improve.

Related to the termination of the 2003 Expansion Project precedent agreements, all but one of the former 2003 Expansion shippers has committed to take capacity on PG&E GTN's system made available as a result of the 2002 shipper termination or capacity formerly held by Enron or other existing capacity on PG&E GTN's system. PG&E GTN anticipates that it will enter into additional contracts for capacity made available from these sources through open market sales. As of December 31, 2002, PG&E GTN had approximately 155,000 Dth per day of capacity available for subscription on a long-term basis.

North Baja Pipeline. North Baja Pipeline, LLC (NBP) owns an approximately 80-mile interstate natural gas pipeline with a capacity of 512 MDth of natural gas per day. The NBP system originates near Ehrenberg, in western Arizona, and traverses southern California to a point on the Baja California, Mexico-California border. The NBP system began limited commercial operation in September 2002 and includes a single compressor station at Ehrenberg, which has approximately 28,800 certificated horsepower and ancillary facilities which include metering and regulating facilities and a communication system. The NBP mainline system consists of approximately 12 miles of 36-inch diameter gas transmission line and 68 miles of 30-inch diameter pipe. This new pipeline will deliver natural gas to a pipeline being constructed by Sempra Energy International. The 135-mile Sempra pipeline will interconnect with PG&E NBP at the California-Mexico border and transport gas into Northern Mexico and Southern California.

North Baja System Interconnections with Other Pipelines

El Paso Natural Gas (EPNG) NBP pipeline facilities interconnect with the facilities of EPNG near Ehrenberg, Arizona. EPNG is an interstate natural gas pipeline, with a pipeline network throughout west Texas, New Mexico and Arizona, that serves customers and other pipelines, including NBP, within those states. Through EPNG, NBP customers have access to gas primarily from the Permian and San Juan basins of Texas, New Mexico and Colorado. EPNG's transportation services are regulated by the FERC.

Gasoducto Bajanorte (GB) NBP pipeline facilities interconnect with the facilities of GB at the Baja California, Mexico-California border near Ogilby, California. GB is the pipeline that receives gas from NPB for the purpose of delivering the gas to customers located in the northern portion of Baja California, Mexico. GB's transportation services are regulated by the Comision Reguladora de Energia, Mexico, a regulatory agency in Mexico with responsibilities similar to those of FERC as they relate to natural gas pipelines.

Iroquois Pipeline. PG&E NEG owns a 5.2% interest in the Iroquois Gas Transmission System, an interstate pipeline which extends 375 miles from the U.S.-Canadian border in northern New York through the State of Connecticut to Long Island, New York. This pipeline, which commenced operations in 1991, provides gas transportation service to local gas distribution companies, electric utilities and electric power generators, directly or indirectly through exchanges and interconnecting pipelines, throughout the Northeast. The Iroquois pipeline is owned by a partnership of six U.S. and Canadian energy companies, including affiliates of TransCanada Pipeline, Dominion Resources and Keyspan Energy. Iroquois has executed firm multi-year transportation services agreements totaling more than 1,000 MMcf per day. This pipeline also provides interruptible transportation services on an as available basis. On December 26, 2001, the FERC issued a certificate of public convenience and necessity authorizing Iroquois to expand its capacity by 220 MMcf per day of natural gas and extend the pipeline into the Bronx borough of New York City for a total investment of approximately $210 million. Iroquois also filed three additional applications with the FERC to expand its system capacity, and to extend the pipeline into Eastern Long Island.

Natural Gas Transportation Services

Under the FERC's current policies, transportation services are classified as either firm or interruptible, and PG&E NEG's fixed and variable costs are allocated between these types of service for ratemaking purposes. PG&E GTN provides firm and interruptible transportation services to third party shippers on a nondiscriminatory basis. Firm transportation services means that the customer has the highest priority rights to ship a quantity of gas between two points for the term of the applicable contract. Firm transportation service customers pay both a reservation charge and a delivery charge. The reservation charge is assessed for a firm shipper's right to transport a specified maximum daily quantity of gas over the term of the shipper's contract, and is payable regardless of the actual volume of gas transported by the shipper. The delivery charge is payable only with respect to the actual volume of gas transported by the shipper. Interruptible transportation service shippers pay only a delivery charge with respect to the actual volume of gas transported by the shipper.

As of December 31, 2002, PG&E GTN had 93.1% of its available long-term capacity held among 48 shippers under long-term transportation contracts. The terms of these long-term firm contracts range between 1 and 40 years into the future, with a volume-weighted average remaining term of these agreements of approximately 11 years as of December 31, 2002. Approximately 95.9% of total transportation revenue was attributable to long-term contracts in 2002.

PG&E GTN also offers short-term firm and interruptible transportation services plus hub services, which allow customers the ability to park or borrow volumes of gas on its pipeline. If weather, maintenance schedules and other conditions allow, additional firm capacity may become available on a short-term basis. PG&E GTN provides interruptible transportation service when capacity is available. Interruptible capacity is provided first to shippers offering to pay the maximum rate and, if necessary, allocated on a pro-rata basis to shippers offering to pay the maximum rate. If capacity remains after maximum tariff nominations are fulfilled, PG&E GTN allocates discounted interruptible space on a highest to lowest total revenue basis.

In 2002, PG&E GTN provided transportation services to 70 customers. These services include capacity utilized via long-term firm, short-term firm, interruptible and hub services contracts. Short-term firm, interruptible and hub services accounted for approximately 4.1% of total transportation revenues in 2002. Approximately 92.8% of transported volumes were attributable to long-term contracts utilization in 2002. Short-term firm and interruptible volumes accounted for the remaining 4.8% and 2.4%, respectively.

The total quantities of natural gas transported on the PG&E GTN pipeline for the years ended December 31, 1998 through 2002 are set forth in the following table:

Year	**Quantities (MDth)**
1998	1,003,266
1999	925,118
2000	966,653
2001	963,126
2002	915,772

At December 31, 2002, 71.8% of North Baja's available long-term capacity was held under long-term firm transportation agreements. Contracts for the remaining long-term capacity on North Baja take effect in 2003, while long-term contracted capacities associated with some contracts increase between 2003 and 2006. At that time 100% of the available long-term capacity on North Baja will be dedicated to long-term contracts ranging between approximately 4 and 22 years into the future. As of December 31, 2002, the volume-weighted average remaining term of all long-term contracted capacities on North Baja was approximately 20 years.

As of December 31, 2002, NBP was providing transportation services for four customers, all of which had long-term firm service transportation agreements. In 2002, all volumes transported on North Baja were associated with long-term transportation service. The total quantity of natural gas transported on the North Baja pipeline (service commenced on the North Baja pipeline on September 1, 2002) through December 31, 2002, was 11,416 MDth.

Ratemaking

PG&E GTN's firm and interruptible transportation services have both maximum rates, which are based upon total costs (fixed and variable) and minimum rates, which are based upon the related variable costs. Rates for GTN were established in its 1994 rate case. Rates for North Baja were established in FERC's initial order certificating construction and operations of its system. The maximum and minimum rates for each service are set forth in tariffs on file with the commission. Both PG&E GTN and North Baja are allowed to vary or discount rates between the maximum and minimum

on a non-discriminatory basis. Neither PG&E GTN nor North Baja have discounted long-term firm transportation service rates, but at times PG&E GTN discounts short-term firm and interruptible transportation service rates in order to maximize revenue. Both pipelines are also authorized to offer firm and interruptible service to shippers under individually negotiated rates. Such rates may be above the maximum rate or below the minimum rate, may vary from a straight-fixed-variable, or SFV, rate design methodology, and may be established with reference to a formula. Such negotiated rates may only be offered to the extent that, at the time the shipper enters into a negotiated rate agreement, that shipper had the option to receive the same service at the recourse rate, which is the maximum rate for that service under PG&E GTN's Tariff.

Both PG&E GTN's and NBP's recourse rates for firm service are designed on an SFV methodology. Under the SFV rate design, a pipeline company's fixed costs, including return on equity and related taxes, associated with firm transportation service are collected through the reservation charge component of the pipeline company's firm transportation service rates. Both pipelines also offer FERC-mandated capacity release mechanisms, under which firm shippers may release capacity to other shippers on a temporary or permanent basis. In the case of a capacity release that is not permanent, a releasing shipper remains responsible to the pipeline for the reservation charges associated with the released capacity. With respect to permanent releases of capacity, the releasing shipper is no longer responsible for the reservation charges associated with the released capacity if the replacement shipper meets the creditworthiness provisions of the pipeline's tariff and agrees to pay the full reservation fee.

Based on its 1994 rate case, PG&E GTN is permitted to recover approximately 97.0% of its fixed costs (as established in 1994) through reservation charges on long-term capacity. As of December 31, 2002, GTN had 93.1% of its available long-term capacity subscribed under long-term firm contracts.

Based on its initial FERC certificate, NBP is permitted to recover 98.1% of its fixed costs through reservation charges on long-term capacity. As of December 31, 2002, North Baja had 71.8% of its available long-term capacity subscribed under long-term contracts. Since these contracts are for fixed negotiated rates, North Baja will only recover a portion of its fixed costs in the initial years.

ENVIRONMENTAL MATTERS

Environmental Matters

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

PG&E Corporation, the Utility, and various PG&E NEG affiliates (including USGen New England, Inc., or USGenNE), are subject to a number of federal, state, and local laws and regulations relating to the protection of the environment and human health and safety. These laws and requirements relate to a broad range of activities, including:

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

The penalties for violation of these laws and requirements can be severe, and may include significant fines, damages, and criminal or civil sanctions. They also may require, under certain circumstances, the interruption or curtailment of operations. To comply with all applicable laws and requirements, the Utility or PG&E NEG may need to spend substantial amounts from time to time to construct or acquire new equipment, acquire permits and/or marketable allowances or other emission credits for facility operations, modify or replace existing equipment and clean up or decommission waste disposal areas at their current or former facilities and at other third-party sites where they may have disposed of or recycled wastes. In the past the Utility generally has recovered the costs of complying with environmental laws and regulations in its rates. In 1994, the CPUC established a ratemaking mechanism for hazardous waste remediation costs under which the Utility is authorized to recover costs for environmental claims (e.g., for cleaning up facilities and sites to which the Utility has sent hazardous wastes) from ratepayers. That mechanism assigns 90% of the includable hazardous substance cleanup costs to Utility ratepayers and 10% to Utility shareholders without a review of the underlying costs. Expenditures to cover environmental costs in the future are likely to be significant; however, based on the Utility's past experience, PG&E Corporation and the Utility believe it will be able to recover most of these costs from ratepayers and its insurers. PG&E Corporation and the Utility cannot assure you, however, that these costs will not be material, or that the Utility will be able to recover its costs in the future.

Environmental Protection Measures

The estimated expenditures of PG&E Corporation's subsidiaries for environmental protection are subject to periodic review and revision to reflect changing technology and evolving regulatory requirements. It is likely that the stringency of environmental regulations will increase in the future.

Air Quality

The Utility's and PG&E NEG's generating plants are subject to numerous air pollution control laws, including the Federal Clean Air Act and similar state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon monoxide, sulfur dioxide, or SO2, nitrogen oxide, or NOx, and particulate matter. Fossil fuel-fired electric utility plants are usually major sources of air pollutants and, therefore are subject to substantial regulation and enforcement oversight by the applicable governmental agencies.

Various multi-pollutant initiatives have been introduced in the U.S. Senate and House of Representatives, including Senate Bill 556 and House Resolutions 1256 and 1335. These initiatives include limits on the emissions of NOx, SO2, mercury, and carbon dioxide, or CO2. Certain of these proposals would allow the use of trading mechanisms to achieve or maintain compliance with the proposed rules.

A multi-state memorandum of understanding dealing with the control of NOx air emissions from major emission sources was signed by the Ozone Transport Commission states in the Mid-Atlantic and Northeastern states. The memorandum of understanding and underlying state laws establish a regional three-phase plan for reducing NOx emissions from electric generating units and large industrial boilers within the Ozone Transport Region.

The NOx allowances available to each facility under the ozone season budget decreases as the program progresses and thus forces an overall reduction in NOx emissions. Under regulatory systems of this type, PG&E NEG may purchase NOx allowances from other sources in the area in addition to those that are allocated to PG&E NEG facilities, instead of installing NOx emission control systems. Depending on the market conditions, the purchase of extra allowances may minimize the total cost of compliance. During Phase 3, PG&E NEG will receive fewer allowances under a reduced NOx budget. PG&E NEG plans to meet the Phase 3 budget level for its Salem Harbor and Brayton Point generating facilities with a combination of allowance purchases and emission control technologies. PG&E NEG expects that the emission reductions to be required under regulations recently issued by the Commonwealth of Massachusetts, described below, significantly reduce its need for allowance purchases.

As a result of the Utility's divestiture of most of its fossil fuel-fired power plants and its geothermal generation facilities, the Utility's NOx emission reduction compliance costs have been reduced significantly. Pursuant to the California Clean Air Act and the Federal Clean Air Act, two of the local air districts in which the Utility owns and operates fossil fuel-fired generating plants have adopted final rules that require a reduction in NOx emissions from the power plants of approximately 90% by 2004 (with numerous interim compliance deadlines).

The Utility's Gas Accord authorized $42 million to be included in rates through 2002 for gas NOx retrofit projects related to natural gas compressor stations on the Utility's Line 300, which delivers gas from the Southwest. The Gas Accord II (the extension of the Gas Accord through 2003) provides for recovery of these costs in rates through 2003, and the Gas Accord II 2004 application requests recovery in rates through 2004. Other air districts are considering NOx rules that would apply to the Utility's other natural gas compressor stations in California. Eventually the rules are likely to require NOx reductions of up to 80% at many of these natural gas compressor stations. Substantially all of these costs will be capital costs.

In addition, certain current regulatory initiatives, particularly at the federal level, could increase the Utility's and PG&E NEG's compliance costs and capital expenditures to comply with laws such as laws relating to emissions of carbon dioxide and other greenhouse gases, particulates, and various other pollutants. If enacted, these programs could require the Utility and PG&E NEG to install additional pollution controls, purchase emission allowances, or curtail operations. Although associated costs could be material, the Utility expects that it would be able to recover these costs from ratepayers. The Utility will be required to incur substantial capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining permits and approvals addressing air emission related issues.

The Federal Clean Air Act's acid rain provisions also require substantial reductions in SO2 emissions. Implementation of the acid rain provisions is achieved through a total cap on SO2 emissions from affected units and an allocation of marketable SO2 allowances to each affected unit. Operators of electric generating units that emit SO2 in excess of their allocations can buy additional allowances from other affected sources.

The EPA also has been conducting a nationwide enforcement investigation regarding the historical compliance of coal-fueled electric generating stations with various permitting requirements of the Federal Clean Air Act. Specifically, the EPA and the U.S. Department of Justice recently have initiated enforcement actions against a number of electric utilities, several of which have entered into substantial settlements for alleged Federal Clean Air Act violations related to modifications (sometimes more than 20 years ago) of existing coal-fired generating facilities. In May 2000, USGenNE received an Information Request from the EPA pursuant to Section 114 of the Federal Clean Air Act. The Information Request asked USGenNE to provide certain information relative to the compliance of USGenNE's Brayton Point and Salem Harbor Generating Stations with the Federal Clean Air Act. No enforcement action has been brought by the EPA to date. USGenNE has had very preliminary discussions with the EPA to explore a potential settlement of this matter. It is not possible to predict whether any such settlement will occur or, in the absence of a settlement, the likelihood of whether the EPA will bring an enforcement action.

In addition to the EPA, states may impose more stringent air emissions requirements. On May 11, 2001, the Massachusetts Department of Environmental Protection (DEP) issued regulations imposing new restrictions on emissions of NOx, SO2, mercury, and CO2 from existing coal- and oil-fired power plants. These restrictions will impose more stringent annual and monthly limits on NOx and SO2 emissions than currently exist and will take effect in stages, beginning in October 2004 if no permits are needed for the changes necessary to comply, and beginning in 2006 if such permits are needed. The regulations contemplate that affected parties will file compliance plans, based on which the DEP would decide whether these permits were required. In addition, mercury emissions are capped as a first step and must be reduced by October 2006 pursuant to standards to be developed. CO2 emissions are regulated for the first time and must be reduced from recent historical levels. USGenNE believes that compliance with the CO2 caps can be achieved through implementation of a number of strategies, including sequestrations and offsite reductions. Various testing and record keeping requirements also are imposed. The new Massachusetts regulations affect primarily USGenNE's Brayton Point and Salem Harbor generating facilities.

USGenNE filed its plan to comply with the new regulations with the DEP at the end of 2001. The DEP has ruled that Brayton Point is required to meet the newer, more stringent emission limitations for SO2 and NOX by 2006. It has also ruled that Salem Harbor is required to meet these limitations by 2004. Although USGenNE intends to appeal DEP's ruling that Salem Harbor must comply with the new reglations by 2004, in the absence of a successful appeal of DEP's ruling, the compliance date for Salem Harbor remains 2004. USGenNE will not be able to operate Salem Harbor unless it is in compliance with these emission limitations. USGenNE believes that it is impossible to meet the 2004 deadline. Consequently, it may be unable to operate the facility beyond the 2004 deadline. Through 2006, and assuming that USGenNE prevails in its appeal of the 2004 deadline, it may be necessary to spend approximately $266 million to comply with these regulations. It is possible that actual expenditures may be higher. USGenNE has not made any commitments to spend these amounts. In the event that USGenNE does not spend required amounts to meet each facility's compliance deadline, USGenNE may not be able to operate the facilities.

The EPA is required under the Federal Clean Air Act to establish new regulations for controlling hazardous air pollutants from combustion turbines and reciprocating internal combustion engines. Although the EPA has yet to propose the regulations, the Federal Clean Air Act required that they be promulgated by November 2000. Another provision in the Federal Clean Air Act requires companies to

submit case-by-case Maximum Achievable Control Technology (MACT) determinations for individual plants if the EPA fails to finalize regulations within eighteen months past the deadline. On April 5, 2002, the EPA promulgated a regulation that extends this deadline for the case-by-case permits until May 2004. The EPA intends to finalize the MACT regulations before this date, thus eliminating the need for the plant-specific permits. It is not possible to accurately quantify the economic impact of the future regulations until more details are available through the rulemaking process.

Global climate change is a significant environmental issue that is likely to require sustained global action and investment over many decades. PG&E Corporation has been engaged on the climate change issue for several years and is working with others on developing appropriate public policy responses to this challenge. PG&E Corporation continuously assesses the financial and operational implications of this issue; however, the outcome and timing of these initiatives are uncertain.

There are six greenhouse gases. The Utility and PG&E NEG emit varying quantities of these greenhouse gases, including CO2 and methane, in the course of their operations. Depending on the ultimate regulatory regime put into place for greenhouse gases, PG&E Corporation's operations, cash flows and financial condition could be adversely affected. Given the uncertainty of the regulatory regime, it is not possible to predict the extent to which climate change regulation will have a material adverse effect on the Utility's or PG&E NEG's financial condition or results of operations.

PG&E NEG and the Utility are taking numerous steps to manage the potential risks associated with the eventual regulation of greenhouse gases, including but not limited to preparing inventories of greenhouse gas emissions, voluntarily reporting on these emissions through a variety of state and federal programs, engaging in demand side management programs that prevent greenhouse gas emissions, and supporting market-based solutions to the climate change challenge.

Water Quality

The Federal Clean Water Act generally prohibits the discharge of any pollutants, including heat, into any body of surface water, except in compliance with a discharge permit issued by a state environmental regulatory agency and/or the EPA. All of PG&E NEG's facilities that are required to have such permits either have them or have timely applied for extensions of expired permits and are operating in substantial compliance with the prior permit. At this time, three of the fossil-fuel plants owned and operated by USGenNE (Manchester Street, Brayton Point, and Salem Harbor stations) are operating pursuant to permits that have expired. For the facilities whose water discharge permits (National Pollutant Discharge Elimination System, or NPDES permits) have expired, permit renewal applications are pending, and USGenNE anticipates that all three facilities will be able to continue to operate in substantial compliance with prior permits until new permits are issued. It is possible that the new permits may contain more stringent limitations than the prior permits.

At Brayton Point, unlike the Manchester Street and Salem Harbor generating facilities, PG&E NEG has agreed to meet certain restrictions that were not in the expired NPDES permit. In October 1996, the EPA announced its intention to seek changes in Brayton Point's NPDES permit based on a report prepared by the Rhode Island Department of Environmental Management, which alleged a connection between declining fish populations in Mt. Hope Bay and thermal discharges from the Brayton Point once-through cooling system. In April 1997, the former owner of Brayton Point entered into a Memorandum of Agreement, or MOA, with various governmental entities regarding the operation of the Brayton Point station cooling water systems pending issuance of a renewed NPDES permit. This MOA, which is binding on PG&E NEG, limits on a seasonal basis the total quantity of heated water that may be discharged to Mt. Hope Bay by the plant. While the MOA is expected to remain in effect until a new NPDES permit is issued, it does not in any way preclude the imposition of more stringent discharge limitations for thermal and other pollutants in a new NPDES permit and it is possible that such limitations will in fact be imposed. On July 22, 2002, the EPA and the DEP issued a

draft NPDES permit for Brayton Point that, among other things, substantially limits the discharge of heat by Brayton Point into Mt. Hope Bay. USGenNE believes that the permit is excessively stringent and estimates that the cost to comply with it could be as much as $248 million through 2006. This is a preliminary estimate. There are various administrative and judicial proceedings that must be completed before the draft NPDES permit becomes final and these proceedings are not expected to be completed during 2003. In addition, the EPA, as well as local environmental groups, have previously expressed concern that the metal vanadium is not addressed at Brayton Point or Salem Harbor under the terms of the old NPDES permits and it may raise this issue in upcoming NPDES permit negotiations. Based upon the lack of an identified control technology, PG&E NEG believes it is unlikely that the EPA will require that vanadium be addressed pursuant to a NPDES permit. However, if the EPA does insist on including vanadium in the NPDES permit, PG&E NEG may have to spend a significant amount to comply with such a provision. If these more stringent discharge limitations are imposed, compliance with them could have a material adverse effect on PG&E NEG's financial condition, cash flows, and results of operations.

The Utility's existing power plants, including Diablo Canyon, also are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. The Utility's fossil fuel-fired power plants comply in all material respects with the discharge constituents standards and the thermal standards. Additionally, pursuant to Section 316(b) of the Federal Clean Water Act, the Utility is required to demonstrate that the location, design, construction, and capacity of power plant cooling water intake structures reflect the best technology available, or BTA, for minimizing adverse environmental impacts at its existing water-cooled thermal plants. The Utility has submitted detailed studies of each power plant's intake structure to various governmental agencies and each plant's existing intake structure was found to meet the BTA requirements.

The Diablo Canyon Power Plant employs a "once through" cooling water system that is regulated under a NPDES permit issued by the Central Coast Regional Water Quality Control Board, or 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, recreation, commercial/sport fishing, 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 meets the BTA requirements. As part of the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $6 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 prior to final approval by the Central Coast Board and, once signed by the parties, 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.

In December 1999, the Utility was notified by the purchaser of the Utility's former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water from the intake, and that this procedure is not specified in the plant's NPDES permit issued by the Central Coast Board. The purchaser notified the Central Coast Board of its findings. In March 2002, the Utility and the Central Coast Board reached a tentative settlement of this matter under which the Utility will fund approximately $5 million in environmental projects related to coastal resources. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in the California Superior Court. The California Attorney General has filed a claim in the Utility's bankruptcy case to preserve the Board's claim.

Additionally, on April 9, 2002, the EPA proposed regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations would affect existing power generation facilities using over 50 million gallons per day (mgd), typically including some form of "once-through" cooling. The Utility's Diablo Canyon, Hunters Point, and Humboldt Bay power plants and PG&E NEG's Brayton Point, Salem Harbor, and Manchester Street generating facilities are among an estimated 539 plants nationwide that would be affected by this rulemaking. The proposed regulations call for a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. Significant capital investment may be required to achieve the standards if the regulations are adopted as proposed. The final regulations are scheduled to be issued in February 2004.

PG&E Corporation and the Utility believe the ultimate outcome of these matters will not have a material impact on their consolidated financial position or results of operations.

The issuance or modification of statutes, regulations, or water quality control plans at the federal, state, or regional level may impose increasingly stringent cooling water discharge requirements on the Utility's and PG&E NEG's power plants in the future. Costs to comply with new permit conditions required to meet more stringent requirements that might be imposed cannot be estimated at the present time.

Endangered Species

Many of the Utility's facilities and operations are located in or pass through areas that are designated as critical habitats for federal- or state-listed endangered, threatened, or sensitive species. The Utility may be required to incur additional costs or be subjected to additional restrictions on operations if additional threatened or endangered species are listed or additional critical habitats are designated near the Utility's facilities or operations.

Hazardous Waste Compliance and Remediation

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

The Utility and PG&E NEG assess, on an ongoing basis, measures that may need to be taken to comply with federal, state and local laws and regulations related to hazardous materials and hazardous waste compliance and remediation activities. The Utility and PG&E NEG have a comprehensive program to comply with hazardous waste storage, handling, and disposal requirements issued by the

EPA under RCRA and CERCLA, along with other state hazardous waste laws and other environmental requirements.

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

Operations at the Utility's current and former power plants may have resulted in contaminated soil or groundwater. Although the Utility has sold most of its fossil fuel-fired and geothermal power plants in connection with electric industry restructuring, in many cases the Utility retained pre-closing environmental liability with respect to these plants under various environmental laws. The Utility currently is investigating or remediating several such sites with the oversight of various governmental agencies. In addition, the federal Toxic Substances Control Act regulates the use, disposal, and cleanup of polychlorinated biphenyls, or PCBs, which are used in certain electrical equipment. During the 1980s, the Utility initiated two major programs to remove from service all of the distribution capacitors and network transformers containing high concentrations of PCBs. These programs removed the vast majority of PCBs existing in the Utility's electric distribution system.

One part of the Utility's program is aimed at assessing whether and to what extent remedial action may be necessary to mitigate potential hazards posed by certain disposal sites and retired manufactured gas plant sites. During their operation in the late 1800s and early 1900s, manufactured gas plants produced lampblack and tar residues. The lampblack and tar residues are byproducts of a process that the Utility, its predecessor companies, and other utilities used as early as the 1850s to manufacture gas from coal and oil. As natural gas became widely available (beginning about 1930), the Utility's manufactured gas plants were removed from service. The residues that may remain at some sites contain chemical compounds that now are classified as hazardous. The Utility owns all or a portion of 28 manufactured gas plant sites. The Utility has a program, in cooperation with environmental agencies, to evaluate and take appropriate action to mitigate any potential health or environmental hazards at sites that are owned by the Utility. The Utility spent approximately $4 million in 2002 and expects to spend approximately $11 million in 2003 on such projects. The Utility expects that expenses will increase as remedial actions related to these sites are approved by regulatory agencies. In addition, approximately 68 other manufactured gas plants in the Utility's service territory are now owned by numerous third parties, and it is possible that the Utility may incur cleanup costs related to these sites in the future.

Under environmental laws such as CERCLA, the Utility has been or may be required to take remedial action at third-party sites used for the disposal of wastes from the Utility's facilities, or to pay for associated cleanup costs or natural resource damages. The Utility is currently aware of 8 such sites where investigation or cleanup activities are currently underway. For example, at the Geothermal Incorporated site in Lake County, California, the Utility has been directed to perform site studies and any necessary remedial measures by regulatory agencies. At the Casmalia disposal facility near Santa Maria, California, the Utility and several other generators of waste sent to the site have entered into a court-approved agreement with the EPA that requires the Utility and the other parties to perform certain site investigation and mitigation measures.

In addition, the Utility has been named as a defendant in several civil lawsuits in which plaintiffs allege that the Utility is responsible for performing or paying for remedial action at sites that the Utility no longer owns or never owned.

The cost of hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. It is reasonably possible that 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. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and the Utility can estimate a range of reasonably likely cleanup costs. 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 current technology, enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the costs at the lower end of this range. At December 31, 2002, the Utility expected to spend $331 million, undiscounted for the effect of future inflation, for hazardous waste remediation costs at identified sites, including divested fossil fuel-fired power plants, where such costs are probable and quantifiable. (Although the Utility has sold most of its fossil fuel-fired power plants, the Utility has retained pre-closing environmental liability with respect to these plants.) 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 be as much as $469 million. The Utility estimated the upper limit of the range of costs 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 cleanup costs at additional sites or if identifiable possible outcomes change.

On June 26, 2001, the Bankruptcy Court authorized the Utility to spend

- 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, if such excess expenditures are necessary in the Utility's reasonable business judgment to prevent imminent harm to public health and safety or the environment (provided that the Utility seeks the Bankruptcy Court's approval of such emergency expenditures at the earliest practicable time).

The California Attorney General, on behalf of various state environmental agencies, filed claims in the Utility's bankruptcy case for environmental remediation at numerous sites totaling approximately $770 million. For most if not all these sites, the Utility is in the process of remediating the sites in cooperation with the relevant agencies and others responsible for contributing to the cleanup or would be doing so in the future, in the normal course of business. The Utility's proposed plan of reorganization provides that either the Utility or the LLCs will satisfy 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.

USGenNE assumed the onsite environmental liability associated with its acquisition of electric generating facilities from New England Electric System in 1998, but did not acquire any off-site liability associated with the past disposal practices at the acquired facilities. PG&E NEG has obtained pollution liability and environmental remediation insurance coverage to limit, to a certain extent, the financial risk associated with the on-site pollution liability at all of its facilities. Recently, the EPA indicated that it might begin to regulate fossil fuel combustion materials, including types of coal ash, as hazardous waste under RCRA. If the EPA implements its initial proposals on this issue, USGenNE may be required to change its current waste management practices and expend significant resources on the increased waste management requirements caused by the EPA's change in policy.

During April 2000, an environmental group served various affiliates of PG&E NEG, including USGenNE, with a notice of intent to file a citizen's suit under RCRA. In September 2000, PG&E NEG signed a series of agreements with the Massachusetts Department of Environmental Protection

and the environmental group to resolve these matters that require USGenNE to alter its existing wastewater treatment facilities at its Brayton Point and Salem Harbor generating facilities. USGenNE began the activities during 2000 and expects to complete them in 2003. USGenNE has incurred expenditures related to these agreements of approximately $4.7 million in 2002, $2.6 million in 2001 and $5.4 million in 2000. In addition to the costs incurred in 2000, 2001 and 2002, at December 31, 2002, USGenNE maintains a reserve in the amount of $6 million relating to its estimate of the remaining environmental expenditures to fulfill its obligations under these agreements.

Potential Recovery of Hazardous Waste Compliance and Remediation Costs

To the extent the Utility knows or can estimate the costs of hazardous waste compliance and remediation costs, the Utility intends to seek recovery for these costs in its filed rates through the normal ratemaking proceedings before the CPUC.

In 1994, the CPUC established a ratemaking mechanism for hazardous waste remediation costs, or HWRC. That mechanism assigns 90% of the includable hazardous substance cleanup costs to utility ratepayers and 10% to utility shareholders, without a reasonableness review of such costs or of underlying activities. Under the HWRC mechanism, 70% of the ratepayer portion of the Utility's cleanup costs is attributed to its gas department and 30% is attributed to its electric department. Insurance recoveries are assigned 70% to shareholders and 30% to ratepayers until both are reimbursed for the costs of pursuing insurance recoveries. The balance of insurance recoveries is allocated 90% to shareholders and 10% to ratepayers until shareholders are reimbursed for their 10% share of cleanup costs. Any unallocated funds remaining are held for five years and then distributed 60% to ratepayers and 40% to shareholders over the next five years. The Utility can seek to recover hazardous substance cleanup costs under the HWRC in the rate proceeding that it deems most appropriate. In connection with electric industry restructuring, the HWRC mechanism may no longer be used to recover electric generation-related cleanup costs for contamination caused by events occurring after January 1, 1998.

For each divested generation facility for which the Utility retained environmental remediation liabilities, the plant's decommissioning cost estimate was adjusted by the Utility's estimated forecast of environmental remediation costs. (The buyers assumed the non-environmental decommissioning liability for these plants.) The CPUC ordered that excess recoveries of environmental and non-environmental decommissioning accruals related to the divested plants be used to offset other transition costs. As of December 31, 2002, the Utility had recovered from ratepayers approximately $138 million for environmental decommissioning accrual related to the divested plants. This amount will earn interest at 3% per year that will be used to meet the future environmental remediation costs for the divested plants. The net decommissioning accruals recovered from ratepayers attributable to the non-environmental liability for the divested plants was approximately $50 million. Because the Utility no longer has this non-environmental decommissioning liability, it has used this excess recovery amount to reduce other transition costs.

The $331 million accrued environmental remediation liability at December 31, 2002, mentioned above, includes

- $138 million related to the pre-closing remediation liability, discounted to present value at 7%, associated with divested generation facilities (see further discussion in the "Generation Divestiture" section of Note 2 of the Notes to the Consolidated Financial Statements of the 2002 Annual Report to Shareholders), and

- $193 million related to remediation costs for those generation facilities, manufactured gas plant sites, gas gathering sites, and compressor stations that the Utility still owns.

Of the $331 million environmental remediation liability, the Utility has recovered $188 million through rates, and expects to recover another $84 million in future rates. The Utility is seeking recovery of the remainder of its costs from insurance carriers and from other third parties as appropriate.

The ultimate amount of recovery from insurance coverage, either in the aggregate or with respect to a particular site, cannot be quantified at this time. Insurance recoveries are subject to the HWRC mechanism discussed above.

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, or Nuclear Waste Act, the U.S. Department of Energy, or the DOE, is responsible for the transportation and ultimate long-term disposal of spent nuclear fuel and high-level radioactive waste. Under the Nuclear Waste Act, utilities are required to provide interim storage facilities until permanent storage facilities are provided by the federal government. The Nuclear Waste Act mandates that one or more such permanent disposal sites be in operation by 1998. Consistent with the law, the Utility signed a contract with the DOE providing for the disposal of the spent nuclear fuel and high-level radioactive waste from the Utility's nuclear power facilities beginning not later than January 1998. However, due to delays in identifying a storage site, the DOE has been unable to meet its contract commitment to begin accepting spent fuel by January 1998. Further, under the DOE's current estimated acceptance schedule for spent fuel, Diablo Canyon's spent fuel may not be accepted by the DOE for interim or permanent storage before 2010, at the earliest. 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 2007 while maintaining the capability for a full-core off-load. It is likely that an interim or permanent DOE storage facility will not be available for Diablo Canyon's spent fuel by 2007. In December 2001, the Utility filed a request with the NRC for a license to build a dry cask storage system to store spent fuel at Diablo Canyon, pending disposal or storage at a DOE facility. A hearing in this proceeding is scheduled for May 2003.

In February 2002, the DOE formally recommended, and President Bush approved, Yucca Mountain, Nevada as the site for a permanent spent fuel repository. The State of Nevada vetoed this site but the U.S. Congress overrode this veto with a House of Representatives vote in May 2002 and a Senate vote in July 2002, and the bill was subsequently signed by President Bush. As a result, the State of Nevada has filed a number of suits in various federal courts to stop the NRC's licensing of the site. If Yucca Mountain is ultimately determined to be acceptable as the repository site, the DOE will proceed with the licensing and eventual construction of the repository and may begin receipt of spent fuel as early as 2010. However, considerable uncertainty exists regarding the time frame under which the DOE will begin to accept spent fuel for storage or disposal. If Yucca Mountain is completed by 2010, the earliest Diablo Canyon's spent fuel would be accepted by Yucca Mountain for storage or disposal would be 2018.

In July 1988, the NRC gave final approval to the Utility to store radioactive waste from the retired nuclear generating unit Humboldt Unit 3 at the plant until 2015 before ultimately decommissioning the unit. The Utility has agreed to remove all spent fuel when the federal disposal site is available. In 1988, the Utility completed the first step in the decommissioning of Humboldt Bay Unit 3 and placed the unit into a custodial mode of decommissioning called SAFSTOR. This is a condition of monitored safe storage in which the unit will be maintained until the spent nuclear fuel is removed from the spent fuel pool and the facility is dismantled. The used fuel assemblies currently are stored in metal racks submerged in a pool of water, i.e., a wet storage pool. The specially designed storage pool is constructed of steel-reinforced concrete and lined with stainless steel. The Utility currently is exploring licensing and permitting of an on-site dry cask storage facility. Transfer of spent fuel to a dry cask facility would allow early decommissioning of Humboldt Bay Unit 3. The Utility anticipates that if it

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were licensed to employ an on-site dry cask storage facility, it would receive a 20-year initial license with the opportunity to receive a 20-year renewal term.

Nuclear Decommissioning

The Utility's nuclear power facilities are scheduled to begin, for ratemaking purposes, decommissioning in 2015 and scheduled for completion in 2041. Nuclear decommissioning means (1) the safe removal of nuclear facilities from service, and (2) the reduction of residual radioactivity to a level that permits termination of the Nuclear Regulatory Commission license and release of the property for unrestricted use.

The estimated total obligation for nuclear decommissioning costs, based on a February 2002 site study, is $1.9 billion in 2002 dollars (or $8.4 billion in future dollars). The Utility's future estimate is based upon its 2001 estimated obligation assuming an annual escalation rate of 5.5% for decommissioning costs. This estimate includes labor, materials, waste disposal charges, and other costs. A contingency of 40% to capture engineering, regulatory, and business environment changes is included in the total estimated obligation. 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 decommissioning funds of 6.34% and on non-tax-qualified decommissioning funds of 5.39%. 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. At December 31, 2002, the total nuclear decommissioning obligation accrued was $1.3 billion.

Since January 1, 1998, nuclear decommissioning costs, which are not transition costs, have been recovered from customers through a non-bypassable charge that will continue until those costs are fully recovered. Recovery of decommissioning costs may be accelerated to the extent possible under the rate freeze. For the year ended December 31, 2002, annual nuclear decommissioning trust contributions collected in rates were $24 million and this amount was contributed to the trusts.

The CPUC has established a Nuclear Decommissioning Costs Triennial Proceeding to determine the decommissioning costs and to establish the annual revenue requirement and attrition factors over subsequent three-year periods. On March 15, 2002, the Utility filed its 2002 Nuclear Decommissioning Cost Triennial Proceeding application seeking to increase its nuclear decommissioning revenue requirements for the years 2003 through 2005 and to begin decommissioning of Humboldt Bay Unit 3 in 2006, instead of 2015. The Utility estimates a total decommissioning cost of approximately $299 million, stated in 2002 dollars, for Humboldt Bay Unit 3 presuming that the CPUC approves this earlier decommissioning schedule. The Utility seeks recovery of $24 million in revenue requirements relating to the Diablo Canyon Nuclear Decommissioning Trusts and $17.5 million in revenue requirements relating to the Humboldt Bay Power Plant Decommissioning Trusts. The Utility also seeks recovery of $7.3 million in CPUC-jurisdictional revenue requirements for Humboldt Bay Unit 3 SAFSTOR operating and maintenance costs, and escalation associated with that amount in 2004 and 2005. The Utility proposes continuing to collect the revenue requirement through a non-bypassable charge in electric rates, and to record the revenue requirement and the associated revenues in a balancing account. The CPUC held hearings on the application in September 2002 and is scheduled to issue a final decision in April 2003.

Decommissioning costs recovered in rates are placed in external trust funds. These funds, along with accumulated earnings, will be used exclusively for decommissioning and dismantling nuclear facilities. The trusts maintain substantially all of their investments in debt and equity securities. All earnings on the funds held in the trusts, net of authorized disbursements from the trusts and management and administrative fees, are reinvested. Monies may not be released from the external trusts until authorized by the CPUC. At December 31, 2002, the Utility had accumulated external trust funds with an estimated liquidation value of $1.3 billion, based on quoted market prices and net of deferred taxes on unrealized gains, to be used for the decommissioning of the Utility's nuclear facilities.

Compressor Station Litigation

Several lawsuits have been filed against Pacific Gas and Electric Company seeking damages from alleged chromium contamination at the Utility's Hinkley, Topock, and Kettleman Compressor Stations. See Item 3 "Legal Proceedings Compressor Station Chromium Litigation" below for a description of the pending litigation.

Electric and Magnetic Fields

Electric and magnetic fields, or EMFs, naturally result from the generation, transmission, distribution and use of electricity. In January 1991, the CPUC opened an investigation into potential interim policy actions to address increasing public concern, especially with respect to schools, regarding potential health risks that may be associated with EMFs from utility facilities. In its order instituting the investigation, the CPUC acknowledged that the scientific community has not reached consensus on the nature of any health impacts from contact with EMFs, but went on to state that a body of evidence has been compiled that raises the question of whether adverse health impacts might exist.

In November 1993, the CPUC adopted an interim EMF policy for California energy utilities that, among other things, requires California energy utilities to take no-cost and low-cost steps to reduce EMFs from new and upgraded utility facilities. California energy utilities were required to fund an EMF education program and an EMF research program managed by the California Department of Health Services. As part of its effort to educate the public about EMFs, the Utility provides interested customers with information regarding the EMF exposure issue. The Utility also provides a free field measurement service to inform customers about EMF levels at different locations in and around their residences or commercial buildings.

In October 2002, the California Department of Health Services released its report, based primarily on its review of studies by others, evaluating the possible risks from electric and magnetic fields to the CPUC and the public. The report's conclusions contrast with other recent reports by authoritative health agencies in that the California Department of Health Services' report has assigned a higher probability to the possibility that there is a causal connection between EMF exposures and a number of diseases and conditions, including childhood leukemia, adult leukemia, amyotrophic lateral sclerosis, and miscarriages.

It is not yet clear what actions the CPUC will take to respond to this report. Possible outcomes include, but are not limited to, continuation of current policies and imposition of more stringent measures to mitigate EMF exposures. The Utility cannot estimate the costs of such mitigation measures with any certainty at this time. However, such costs could be significant, depending on the particular mitigation measures undertaken, especially if relocation of existing power lines ultimately is required.

The Utility currently is not involved in third-party litigation concerning EMFs. In August 1996, the California Supreme Court held that homeowners are barred from suing utilities for alleged property value losses caused by fear of EMFs from power lines. The Court expressly limited its holding to property value issues, leaving open the question as to whether lawsuits for alleged personal injury resulting from exposure to EMFs are similarly barred. The Utility was a defendant in civil litigation in which plaintiffs alleged personal injuries resulting from exposure to EMFs. In January 1998, the appeals court in this matter held that the CPUC has exclusive jurisdiction over personal injury and wrongful death claims arising from allegations of harmful exposure to EMFs and barred plaintiffs' personal injury claims. Plaintiffs filed an appeal of this decision with the California Supreme Court. The California Supreme Court declined to hear the case.

Low Emission Vehicle Programs

In December 1995, the CPUC issued its decision in the Low Emission Vehicle (LEV) proceeding, which approved approximately $42 million in funding for the Utility's LEV program for the six-year period beginning in 1996. The LEV program expired on December 20, 2001. On January 23, 2002, the CPUC approved bridge funding of $7 million for the LEV program. On March 25, 2002, the Utility requested that the CPUC approve funding for the continuation of its LEV program. The other California utilities filed similar requests. In June 2002, the CPUC determined that issues related to research, development and demonstration, and customer education would be heard in the LEV proceeding, but that issues related to fleet vehicle acquisition, fueling and charging infrastructure, and operation and maintenance of Utility infrastructure would be addressed in the Utility's 2003 General Rate Case. Hearings in the LEV proceeding were held in August 2002. The 2003 General Rate Case was filed in November 2002. The Utility has requested funding of $5 million in the LEV proceeding and approximately $7.4 million for LEV-related costs in the 2003 General Rate Case. On December 19, 2002, LEV interim funding of $7 million was extended pending the CPUC's final decisions in both the LEV proceedings and the General Rate Case. A final decision in the LEV proceeding is expected by the end of March 2003.

PART II

ITEM 5. Market for the Registrant's Common Equity and Related Stockholder Matters.

Information responding to part of Item 5, for each of PG&E Corporation and Pacific Gas and Electric Company, is set forth under the heading "Quarterly Consolidated Financial Data (Unaudited)", which information is hereby included as part of this amended report. As of February 1, 2003, there were 117,812 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York, Pacific, and Swiss stock exchanges. The discussion of dividends with respect to PG&E Corporation's common stock is in the"Management's Discussion and Analysis of Financial Condition and Results of Operations Dividends" included as part of this amended report.

On June 25, 2002, PG&E Corporation issued to certain lenders warrants to purchase approximately 2.4 million shares of PG&E Corporation common stock at an exercise price of $0.01 per share. On October 18, 2002, PG&E Corporation issued to certain lenders additional warrants to purchase approximately 2.7 million shares of PG&E Corporation common stock. The terms and provisions of the warrants, including a warrant exercise price of $0.01 per share, are substantially identical to the warrants issued on June 25, 2002. The issuance of the warrants by PG&E Corporation was not registered under the Securities Act of 1933 in reliance on the exemption afforded by Section 4(2).

Also, on June 25, 2002, PG&E Corporation issued $280 million aggregate principal amount of 7.50% Convertible Subordinated Notes due June 30, 2007. On October 18, 2002, the notes and the related indenture were amended to delete certain cross-default provisions, to increase the interest rate on the notes to 9.50% from 7.50%, to extend the maturity of the notes to June 30, 2010, from June 30, 2007, and to provide the holder of the notes with a one-time right to require PG&E Corporation to repurchase the notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including any liquidated damages and pass-through dividends, if any). The notes are unsecured and are subordinate to other PG&E Corporation debt. PG&E Corporation has the right, subject to certain limitations, to pay interest by issuing additional notes in lieu of paying cash. In addition to interest, if PG&E Corporation pays cash dividends to holders of its common stock, note holders are entitled to receive cash equal to the dividends that would have been paid with respect to the number of shares that the holder would be entitled to receive if the notes had been converted on the dividend record date. The notes may be converted by the holders into shares of PG&E Corporation common stock at a conversion price of $15.0873 per share. The conversion price is subject to adjustment under certain circumstances, including upon consummation of any spin-off transaction of the Utility as proposed in its plan of reorganization or a spin-off of the shares of PG&E NEG. The issuance of the notes by PG&E Corporation was not registered under the Securities Act of 1933 in reliance on the exemption afforded by Section 4(2).

All obligations of PG&E Corporation with respect to certain loans are secured by a perfected first-priority security interest in the outstanding common stock of PG&E Corporation's subsidiary, the Utility, and all proceeds thereof. With respect to 35% of such common stock pledged for the benefit of the lenders, the lenders have customary rights of a pledgee of common stock, provided that certain regulatory approvals may be required in connection with any foreclosure on such stock. With respect to the remaining 65%, such common stock has been pledged for the benefit of the lenders, but the lenders have no ability to control such common stock under any circumstances and do not have any of the typical rights and remedies of a secured creditor. However, the lenders do have the right to receive any cash proceeds received upon a disposition of such common stock. PG&E Corporation may substitute common stock of Newco, a new corporation formed to hold the equity interests in the LLCs, for the common stock of the Utility in connection with the consummation of the Utility's plan of

reorganization. The loans are also secured by substantially all assets of PG&E Corporation and continue to be secured by PG&E Corporation's ownership interest in PG&E National Energy Group, LLC, or PG&E NEG LLC, which is a Delaware limited liability company and the owner of the shares of PG&E NEG and PG&E NEG LLC's equity interest in PG&E NEG.

PG&E Corporation has agreed to provide, following consummation of a plan of reorganization of the Utility, registration rights in connection with the shares issuable upon conversion of the notes and exercise of the warrants.

Finally, in connection with the original credit agreement, the lenders had received an option to purchase up to 3% of the shares of PG&E NEG. Under the original credit agreement, PG&E Corporation's exercise of each of its one-year extensions of the loan was conditioned upon PG&E NEG granting affiliates of the lenders an additional option to purchase 1% of the common stock of PG&E NEG, determined on a fully-diluted basis, at an exercise price of $1.00. In connection with a new credit agreement entered into on June 25, 2002, the 1% was reduced to approximately .87% of the common stock of PG&E NEG or up to 2.61%. On September 3, 2002, General Electric Capital Corporation, or GECC, gave PG&E Corporation notice that it would put its options to PG&E Corporation under the Option Agreement, and GECC and PG&E Corporation were engaged in a process of appraising the options as provided under the Option Agreement. On October 30, 2002, before the completion of the appraisal process, GECC gave notice of cancellation of its put notice, which was accepted by PG&E Corporation. GECC no longer has the right to put these options to PG&E Corporation. On February 25, 2003, GECC exercised the options, which otherwise would have expired on March 1, 2003. PG&E Corporation and PG&E NEG LLC have agreed with the other holders of options under the Option Agreement that they may exercise their put option any time before March 1, 2003. These options must in any event also be exercised before March 1, 2003. The issuance of the put option by PG&E Corporation was not registered under the Securities Act of 1933 in reliance on the exemption afforded by Section 4(2).

Pacific Gas and Electric Company did not make any sales of unregistered equity securities during 2002, the period covered by this report.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California that conducts its business through two principal subsidiaries: Pacific Gas and Electric Company (the Utility), an operating public utility engaged primarily in the business of providing electricity, natural gas distribution, and transmission services throughout most of Northern and Central California, and PG&E National Energy Group, Inc. (PG&E NEG), a company engaged in power generation, wholesale energy marketing and trading, risk management, and natural gas transmission.

The Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the Bankruptcy Court for the Northern District of California (Bankruptcy Court) on April 6, 2001. 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. The factors causing the Utility to take this action are discussed in this Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) and in Note 2 of the Notes to the Consolidated Financial Statements.

PG&E NEG and its subsidiaries are principally located in the United States and Canada and 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, including North Baja Pipeline, LLC (NBP) (collectively, PG&E GTN).

PG&E NEG also has other less significant subsidiaries.

PG&E National Energy Group, LLC owns 100 percent of the stock of PG&E NEG, GTN Holdings, LLC owns 100 percent of the stock of PG&E GTN, and PG&E Energy Trading Holdings, LLC owns 100 percent of the stock of PG&E ET. The organizational documents of PG&E NEG and these limited liability companies require unanimous approval of their respective boards of directors, including at least one independent director, before they can:

- Consolidate or merge with any entity;
- Transfer substantially all of their assets to any entity; or
- Institute or consent to bankruptcy, insolvency or similar proceedings or actions.

The limited liability 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.

As a result of the sustained downturn in the power industry, PG&E NEG and its affiliates have experienced a financial downturn, which caused the major credit rating agencies to downgrade PG&E NEG's and its affiliates' credit ratings to below investment grade. PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling approximately $2.5 billion, but this debt is non-recourse to PG&E NEG. PG&E NEG and these subsidiaries continue to negotiate with their lenders regarding a restructuring of this indebtedness and these commitments. The factors affecting PG&E NEG's business causing these defaults and the principal actions being taken by PG&E NEG are discussed later in this MD&A and in Note 3 of the Notes to the Consolidated Financial Statements.

During the fourth quarter of 2002, PG&E NEG and certain subsidiaries have agreed to sell or have sold certain assets, have abandoned other assets, and have significantly reduced energy trading operations. As a result of these actions, PG&E NEG has incurred pre-tax charges to earnings of approximately $3.9 billion in 2002. PG&E NEG and its subsidiaries are continuing their efforts to abandon, sell, or transfer additional assets in an ongoing effort to raise cash and reduce debt, whether through negotiation with lenders or otherwise. As a result, PG&E

NEG expects to incur additional substantial charges to earnings in 2003 as it restructures its operations. In addition, if a restructuring agreement is not reached and the lenders exercise their default remedies, or if the financial commitments are not restructured, PG&E NEG and certain of its subsidiaries may be compelled to seek protection under or be forced into a proceeding under the Bankruptcy Code. Management does not expect that the liquidity constraints of PG&E NEG and its subsidiaries will affect the financial condition of PG&E Corporation or the Utility.

PG&E Corporation has identified three reportable operating segments:

- Utility;
- Integrated Energy and Marketing, or the Generation Business; and
- Interstate Pipeline Operations, or the Pipeline Business.

These segments were determined based on similarities in the following characteristics:

- Economic;
- Products and services;
- Types of customers;
- Methods of distribution;
- Regulatory environment; and
- How information is reported to and used by PG&E Corporation's chief operating decision makers.

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.

This discussion and analysis explains the general financial condition and the results of operations of PG&E Corporation and its subsidiaries including:

- Factors that affect each business;
- A comparison of revenues and expenses and why they changed between years;
- Where earnings came from;
- How all of this affects overall financial condition;

- What expenditures for capital projects were for 2000 through 2002, and are expected to be through 2004; and

- The expected sources of cash for future capital expenditures.

This is a combined annual report of PG&E Corporation and the Utility and includes separate Consolidated Financial Statements for each of these two entities. 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.

Forward-looking statements and risk factors

This combined annual report, including the Letter to Shareholders and this MD&A, contains forward-looking statements 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," "could," "should," "would," "may," 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 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:

Recovery of Under-collected Power Procurement and Transition Costs Previously Written Off. The extent to which the Utility is able to recover its under-collected power procurement and transition costs previously written off depends on many factors, including:

- What costs the California Public Utilities Commission (CPUC) determines are eligible for recovery as transition costs;

- When the Utility's rate freeze ended, as determined by the CPUC;

- Sales volatility and the level of direct access customers (i.e., those customers who choose an alternative energy provider);

- Changes in the California Department of Water Resources' (DWR), revenue requirements required to be remitted to the DWR from existing retail rates;

- Changes in the Utility's authorized revenue requirements;

- Future regulatory or judicial decisions that determine whether the Utility is allowed under state law to recover under-collected power procurement and transition costs from its customers after the end of the rate freeze; and

- The outcome of the Utility's claims against the CPUC Commissioners for recovery of under-collected power procurement and transition costs based on the federal filed rate doctrine.

Refundability of Amounts Previously Collected. Whether the Utility is required to refund to ratepayers amounts previously collected depends on many factors including:

Whether the CPUC determines that certain transition or procurement costs recovered in revenues collected by the Utility were not eligible transition costs or otherwise reduces the amount of revenues authorized to recover such transition or procurement costs;

Whether the CPUC ultimately determines that certain past power procurement costs incurred by the Utility were not reasonably incurred and should be disallowed; and

The purposes for which the CPUC ultimately determines that surcharges approved by the CPUC in January, March, and May 2001 may be used.

Outcome of the Utility's Bankruptcy Case. The pace and outcome of the Utility's bankruptcy case will be affected by:

Whether the Bankruptcy Court confirms the Utility's proposed plan of reorganization (Utility's Plan), the alternative plan sponsored by the CPUC and the Official Committee of Unsecured Creditors (the CPUC/OCC Plan), or some other plan of reorganization;

Whether regulatory and governmental approvals required to implement a confirmed plan are obtained and the timing of such approvals;

Whether there are any delays in implementation of a plan due to litigation related to regulatory, governmental, or Bankruptcy Court orders; and

Future equity or debt market conditions, future interest rates, future credit ratings, and other factors that may affect the ability to implement either plan or affect the amount and value of the securities proposed to be issued under either plan.

Operating Environment. The amount of operating income and cash flows the Utility may record may be influenced by the following:

Future regulatory actions regarding the Utility's procurement of power for its retail customers;

The terms and conditions of the Utility's long-term generation procurement plan as approved by the CPUC;

The ability of the Utility to timely recover in full its costs including its procurement costs;

Future sales levels, which can be affected by general economic and financial market conditions, changes in interest rates, weather, conservation efforts, outages, and the level of direct access customers;

The demand for and pricing of natural gas transportation and storage services, which may be affected by weather, overall gas fired generation, and price spreads between various natural gas delivery points;

Changes in the Utility's authorized revenue requirements; and

Acts of terrorism, storms, earthquakes, accidents, mechanical breakdowns, or other events or perils that result in power outages or damages to the Utility's assets or operations, to the extent not covered by insurance.

Legislative and Regulatory Environment. PG&E Corporation's and the Utility's business may be impacted:

- By legislative or regulatory changes affecting the electric and natural gas industries in the United States; and

- By heightened regulatory and enforcement agency focus on the merchant energy business including investigations into "wash" or "round-trip" trading, specific trading strategies and other industry issues, with the potential for changes in industry regulations and in the treatment of PG&E NEG by state and federal agencies.

Regulatory Proceedings and Investigations. PG&E Corporation's and the Utility's business may be affected by:

- The outcome of the Utility's various regulatory proceedings pending at the CPUC and at the Federal Energy Regulatory Commission (FERC); and

- The outcome of the CPUC's pending investigation into whether the California investor-owned utilities (IOUs), have complied with past CPUC decisions, rules or orders authorizing their holding company formations and/or governing affiliate transactions, as well as applicable statutes.

Pending Legal Proceedings. PG&E Corporation's and the Utility's future results of operation and financial conditions may be affected by the outcomes of:

- The lawsuits filed by the California Attorney General and the City and County of San Francisco 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;

- 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

- Other pending litigation.

Competition. PG&E Corporation's and the Utility's future results of operations and financial condition may be affected by:

- The threat of municipalization which may result in stranded Utility investment, loss of customer growth, and additional barriers to cost recovery;

- Changes in the level of direct access customer cost responsibility and other surcharges related to direct access, and competition from other service providers to the extent restrictions on direct access are removed;

- The development of alternative energy technologies;

- The ability to compete for gas transmission services into Southern California and with alternative storage providers throughout California; and

- The growth of distributed generation or self-generation.

Environmental and Nuclear Matters. PG&E Corporation's and the Utility's future results of operations and financial condition may be affected by:

- The effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant;
- Whether the Utility is able to fully recover in rates the costs of complying with existing and future environmental laws, regulations, and policies, the cost of which could be significant; and
- Whether the Utility incurs costs in connection with its nuclear facilities that exceed the Utility's insurance coverage and other amounts set aside for decommissioning and other potential liabilities.

Accounting and Risk Management. PG&E Corporation's and the Utility's future results of operations and financial condition may be affected by:

- The effect of new accounting pronouncements;
- Changes in critical accounting estimates;
- Volatility in income resulting from mark-to-market accounting and changes in mark-to-market methodologies;
- The extent to which the assumptions underlying critical accounting estimates, mark-to-market accounting, and risk management programs are not realized; and
- The volatility of commodity fuel and electricity prices, and the effectiveness of risk management policies and procedures designed to address volatility.

Efforts to Restructure PG&E NEG's Indebtedness. Whether PG&E NEG and certain of its subsidiaries seek protection under or are forced into a proceeding under the Bankruptcy Code will be affected by:

- The outcome of PG&E NEG's negotiations with lenders under various credit facilities, as well as with representatives of the holders of PG&E NEG's Senior Notes, to restructure PG&E NEG's and its subsidiaries' indebtedness and commitments;
- The terms and conditions of any sale, transfer, or abandonment of certain of PG&E NEG's merchant assets, including its New England generating assets, that PG&E NEG may enter into; and
- The terms and conditions under which certain generating projects will be transferred to the project lenders as required by recent restructuring agreements.

PG&E NEG Operational Risks. PG&E Corporation's future results of operation and financial condition will be affected by:

- The extent to which PG&E NEG incurs further charges to earnings as a result of the abandonment, sale or transfer of assets, or termination of contractual commitments, whether such transactions occur in connection with restructuring of PG&E NEG's indebtedness or otherwise;

Any potential charges to income that would result from the reduction and potential discontinuance of PG&E NEG's energy trading and marketing operations, including tolling transactions;

Any potential charges to income that would result from the discontinuance or transfer of any of PG&E NEG's merchant generation assets;

The inability of PG&E NEG, its merchant asset and other subsidiaries, including US Gen New England, Inc., to maintain sufficient liquidity necessary to meet their commodity and other obligations.

The extent to which PG&E NEG's current construction 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 construction projects are delayed or prevented because of financial or liquidity constraints, changes in the national energy markets and by the extent and timing of generating, pipeline, and storage capacity expansion and retirements by others; or by 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 and the potential loss of permits or other rights in connection with PG&E NEG's decision to delay or defer construction;

The impact of layoffs and loss of personnel at PG&E NEG; and

Future sales levels which can be affected by economic conditions, weather, conservation efforts, outages, and other factors.

Current Conditions in the Energy Markets and the Economy. PG&E Corporation's future results of operations and financial condition will be affected by changes in the energy markets, changes in the general economy, wars, embargoes, financial markets, interest rates, other industry participant failures, the markets' perception of energy merchants and other factors.

Actions of PG&E NEG Counterparties. PG&E Corporation's future results of operations and financial condition may be affected by:

The extent to which counterparties demand additional collateral in connection with PG&E ET's trading and nontrading activities and the ability of PG&E NEG and its subsidiaries to meet the liquidity calls that may be made; and

The extent to which counterparties seek to terminate tolling agreements and the amount of any termination damages they may seek to recover from PG&E NEG as guarantor.

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

This MD&A should be read in conjunction with the Consolidated Financial Statements and Notes to the Consolidated Financial Statements included herein.

Market Conditions and Business Environment

During 2002, adverse changes in the electric power and gas utility industry and energy markets affected PG&E Corporation, the Utility, and PG&E NEG's business including:

Contractions and instability of wholesale electricity and energy commodity markets;

Significant decline in generation margins (spark spreads) caused by excess supply and reduced demand in most regions of the United States;

Loss of confidence in energy companies due to increased scrutiny by regulators, elected officials, and investors as a result of a string of financial reporting scandals;

Heightened scrutiny by credit rating agencies prompted by these market changes and scandals which resulted in lower credit ratings for many market participants; and

Resulting significant financial distress and liquidity problems among market participants leading to numerous financial restructurings and less market participation.

LIQUIDITY AND FINANCIAL RESOURCES

Utility

In 1998, the State of California implemented electric industry restructuring and established a framework allowing generators and other electricity providers to charge market-based prices for electricity sold on the wholesale market. The implementing legislation also established a retail electricity rate freeze and a plan for recovery of generation-related costs that were expected to be uneconomic under the new market framework. State regulatory action further strongly encouraged the Utility to sell a majority of its fossil fuel-fired generation facilities and made it economically unattractive to retain its remaining generation facilities. The resulting sales of generation facilities in turn made the Utility more dependent on the newly deregulated wholesale electricity market. Beginning in June 2000, wholesale prices for electricity began to increase. Prices moderated somewhat in the fall before increasing to unprecedented levels in November 2000 and later months. Since the Utility's retail rates were frozen, it financed the higher costs of wholesale electricity by issuing debt and drawing on its credit facilities. The Utility's inability to recover its electric procurement costs from customers ultimately resulted in billions of dollars in defaulted debt and unpaid bills and caused the Utility to file a voluntary petition for relief under the Bankruptcy Code in the Bankruptcy Court on April 6, 2001.

While in bankruptcy, the Utility is not allowed to pay liabilities incurred before it filed for bankruptcy without permission from the Bankruptcy Court. Additionally,

While in bankruptcy, the Utility does not have access to external funding from capital markets;

The Utility is in default under its credit facilities, commercial paper, floating rate notes, senior notes, pollution control loan agreements, and medium-term notes, as a result of its failure to pay certain of its obligations. However, the event of default under each security has been stayed in accordance with the bankruptcy proceedings; and

The Utility has been making capital investments (investments in property, plant, and equipment) out of its cash on hand under the supervision of the Bankruptcy Court. The Utility anticipates that it will be able to continue making such necessary capital investments in the future, subject to Bankruptcy Court approval.

As a result of the California energy crisis and the Utility's bankruptcy filing, a number of qualifying facilities (QFs) requested the Bankruptcy Court to either terminate their contracts to sell electricity to the Utility, or have the contracts suspended for the summer of 2001 so the QFs could sell electricity at market-based rates. Since July 2001, the Utility has entered into 264 five-year agreements

with QFs (authorized by the Bankruptcy Court) to assume their power purchase agreements. See Note 16 of the Notes to the Consolidated Financial Statements for a discussion of the QF power purchase agreements.

In March 2002, the Bankruptcy Court authorized the Utility to pay certain pre- and post-petition interest on certain claims prior to emerging from bankruptcy. The Bankruptcy Court also authorized the Utility to make certain principal payments on pre-petition secured debt that has matured. See the Cash Flows section of this MD&A for a discussion of the Utility's interest and principal payments made during 2002.

Since filing for bankruptcy, the Utility has been accruing interest on its pre-petition liabilities at the required rates included in the Utility's proposed plan of reorganization. As a result, the payment of such interest did not have a material adverse impact on its financial condition or results of operations.

The Utility will continue to accrue interest on its pre-petition liabilities at the required rates in 2003. However, due to the uncertainty of the ultimate outcome of the bankruptcy proceedings, the Utility is not able to estimate the amount of interest that will be paid in 2003.

The Utility and PG&E Corporation have jointly filed a proposed plan of reorganization (Plan) that, if approved, would enable the Utility to emerge from bankruptcy. The Utility Plan, and an alternative plan proposed by the CPUC and the OCC are currently moving through the Chapter 11 process. In November 2002, the Bankruptcy Court began the confirmation trial to determine which plan, if any, the Bankruptcy Court will confirm. The Bankruptcy Court has scheduled hearing dates through the end of March 2003. PG&E Corporation and the Utility are not able to predict the ultimate outcome of the Utility's bankruptcy proceedings, including which plan, if any, the Bankruptcy Court may confirm.

Both the Plan and the alternative plan propose issuing new debt as part of the reorganization. PG&E Corporation and the Utility have incurred, and will continue to incur throughout the reorganization process, legal, accounting, trustee, and other fees associated with the debt issuance. In addition, PG&E Corporation and the Utility have incurred and will continue to incur consulting fees for assistance with the implementation of either plan. The majority of the debt issuance fees and consulting expenses incurred thus far have been expensed and are included in Reorganization Professional Fees and Expenses in the Consolidated Statements of Operations, though a small amount has been capitalized. The Utility will continue to expense costs associated with the reorganization process that do not specifically relate to certain services associated with issuing new debt.

On January 1, 2003, the IOUs, including the Utility, resumed procuring electricity to meet their customers' net open position under California Senate Bill (SB) 1976. For discussion of the requirements contained in SB 1976, see "Regulatory Matters" section of the MD&A and Note 2 of the Notes to the Consolidated Financial Statements.

See Note 2 of the Notes to the Consolidated Financial Statements for further discussion of the California energy crisis, the Utility's voluntary petition for relief under the Bankruptcy Code, and the status of the Chapter 11 confirmation hearings.

PG&E NEG

PG&E NEG has been significantly impacted by adverse changes in the energy markets in 2002. New generation came online while the demand for power was dropping. This oversupply and reduced demand resulted in low spark spreads (the net of power prices less fuel costs) and depressed operating margins. These changes in the power industry have had a significant negative impact on the financial results and liquidity of PG&E NEG. Before July 31, 2002, most of the various debt instruments of PG&E NEG and its affiliates carried investment grade credit ratings assigned by Standard & Poor's

Ratings Group (S&P) and Moody's Investors Service (Moody's). Since July 31, 2002, these credit rating agencies have downgraded all of PG&E NEG's debt facilities to below investment grade.

PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling approximately $2.5 billion, but this debt is non-recourse to PG&E NEG. On November 14, 2002, PG&E NEG defaulted on the repayment of its $431 million 364-day tranche of its corporate revolving credit facility (Corporate Revolver). This resulted in a default under the two-year tranche of the Corporate Revolver, which had an outstanding balance of $273 million at December 31, 2002, the majority of which supports outstanding letters of credit. The default under the Corporate Revolver also constitutes a cross-default under PG&E NEG's (amounts outstanding at December 31, 2002): (1) Senior Notes ($1 billion), (2) guarantee of its turbine revolving credit facility (Turbine Revolver) ($205 million), and (3) equity commitment guarantees for GenHoldings I, LLC's (Gen Holdings) credit facility ($355 million), La Paloma credit facility ($375 million) and Lake Road credit facility ($230 million). In addition, on November 15, 2002, PG&E NEG failed to pay a $52 million interest payment due under the Senior Notes. PG&E NEG does not currently have sufficient cash to meet its financial obligations and has ceased making payments on its debt and equity commitments.

PG&E NEG, and its subsidiaries are restructuring their operations to increase cash, reduce financial obligations, dispose of merchant plant facilities, and decrease energy trading operations. PG&E NEG's objective is to limit its asset trading and risk management activities to only what is necessary for energy management services to facilitate the transition of PG&E NEG's merchant generation facilities through their sale, transfer or abandonment. PG&E NEG will then further reduce and transition to only retain limited capabilities to ensure fuel procurement and power logistics for PG&E NEG's retained independent power plant operations. These restructuring activities have caused material charges to earnings in 2002, and are anticipated to cause substantial additional charges to earnings in 2003.

PG&E NEG, its subsidiaries and their lenders are engaged in discussions regarding restructuring of these commitments. If a restructuring agreement is not reached and the lenders exercise their default remedies, or if the financial commitments are not restructured, PG&E NEG and certain of its subsidiaries may be compelled to seek protection under or be forced involuntarily into proceedings under the Bankruptcy Code.

PG&E Corporation is participating with PG&E NEG, its subsidiaries and their lenders in negotiations to restructure PG&E NEG's and its subsidiaries' commitments. However, under the terms of its credit agreement, PG&E Corporation is limited as to the amount and conditions under which it can provide cash to PG&E NEG. In particular, the Credit Agreement limits PG&E Corporation's ability to make investments in PG&E NEG and its subsidiaries from existing cash to 75 percent of the net cash tax savings (less certain costs and expenses) actually received by PG&E Corporation as a result of certain sales and debt restructuring transactions of PG&E NEG and its subsidiaries. See further details in "PG&E Corporation Debt Financing" below.

If the negotiations with PG&E NEG's lenders prove unsuccessful and if lenders exercise their default remedies and PG&E NEG is forced to seek protection under or is forced into a proceeding under the Bankruptcy Code, management does not expect the liquidity constraints at PG&E NEG and its subsidiaries will affect the financial condition of PG&E Corporation or the Utility.

Asset transfers, sales and abandonments, liquidity issues, and restructuring activities have resulted in substantial charges to earnings in 2002. In addition, PG&E NEG and its subsidiaries expect to incur additional substantial charges to earnings in 2003 primarily related to:

- The reduction in energy trading activities;

- The possible settlement of tolling arrangements, see discussion of tolling agreements in this MD&A under Commitments and Capital Expenditures Tolling Agreements;

- Charges related to the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations" (see discussion in this MD&A under Accounting Pronouncements issued but not yet adopted);

- A possible settlement under the Attala tolling agreement and related lease (see discussion below in Impairments, Write-offs, and Other Charges);

- Potential conversion of existing debt and equity funding commitments to new discounted obligations, including potential write-offs of deferred financing costs; and

- Further restructuring costs.

Impairments, Write-offs, and Other Charges

The following table outlines the pre-tax charges for impairments, write-offs, and other charges that PG&E NEG and its subsidiaries recorded:

(in millions)	**Fourth Quarter 2002**	**Year Ended December 31, 2002**

(in millions)	Fourth Quarter 2002	Year Ended December 31, 2002
Impairment of GenHoldings projects	$ 1,147	$ 1,147
Impairment of Lake Road and La Paloma projects	452	452
Impairment of Mantua Creek project	279	279
Impairment of Turbines & Other Related Equipment costs	30	276
Termination of Interest Rate Swaps on Lake Road, La Paloma, and GenHoldings projects	189	189
Impairment of Dispersed Generation	88	118
Impairment of Goodwill		95
Impairment of Project Development Costs	57	76
Impairment of Southaven Loan	74	74
Impairment of Prepaid Rents related to the Attala lease	43	43
Impairment of Kentucky Hydro project	18	18
Total Pre-tax Impairments, Write-offs, and Other Charges	$ 2,377	$ 2,767
Discontinued Operations Pre-tax Loss on disposal of USGen New England, Inc.	1,123	1,123
Pre-tax loss on disposal of ET Canada	25	25
Total Pre-tax Charges	$ 3,525	$ 3,915

Impairment of GenHoldings I LLC Projects: GenHoldings, a subsidiary of PG&E NEG, is obligated under its credit facility to make equity contributions to fund construction of the Athens, Covert and Harquahala generating projects. This credit facility is secured by these projects in addition to the Millennium generating facility. GenHoldings defaulted under its credit agreement in October 2002 by failing to make equity contributions to fund construction draws for the Athens, Covert and Harquahala generating projects. Although PG&E NEG has guaranteed GenHoldings' obligation to make equity contributions of up to $355 million, PG&E NEG notified the GenHoldings' lenders that it would not make further equity contributions on behalf of GenHoldings. In November and December 2002, the lenders executed waivers and amendments to the credit agreement under which they agreed to continue to waive until March 31, 2003, the default caused by GenHoldings' failure to make equity contributions. In addition, certain of these lenders have agreed to increase their loan commitments to an amount sufficient to provide: (1) the funds necessary to complete construction of the Athens, Covert and Harquahala facilities; and (2) additional working capital facilities to enable each project, including

Millennium, to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent transmission operator requirements. The November and December increased loan commitments rank equally with each other but are senior to amounts loaned through and including the October credit extension.

In consideration of the lenders' forbearance and additional funding, PG&E NEG and GenHoldings have agreed to cooperate with any reasonable proposal by the lenders regarding disposition of the equity in or assets of any or all of the GenHoldings subsidiaries holding the Athens, Covert, Harquahala, and Millennium projects in connection with the restructuring of PG&E NEG's and it subsidiaries' financial commitments to such lenders. The amended credit agreement provides that an event of default will occur if the Athens, Covert, Harquahala, and Millennium projects are not transferred to the lenders or their designees on or before March 31, 2003. Such a default would trigger lender remedies, including the right to foreclose on the projects. Under the waiver, PG&E NEG has re-affirmed its guarantee of GenHoldings' obligation to make equity contributions of approximately $355 million to these projects. Neither PG&E NEG nor GenHoldings currently expects to have sufficient funds to make this payment. The requirement to pay $355 million remains an obligation of PG&E NEG that would survive the transfer of the projects.

In accordance with the provisions of SFAS No. 144 "Accounting For the Impairment or Disposal of Long-Lived Assets," the long-lived assets of GenHoldings at December 31, 2002 were tested for impairment. As a result of the test, the assets were determined to be impaired and were written-down to fair value. Based on the current estimated fair value of these assets, GenHoldings recorded a pre-tax loss from impairment of $1.147 billion in the fourth quarter of 2002.

Impairment of Lake Road and La Paloma Projects: On November 14, 2002, PG&E NEG defaulted under its equity commitment guarantees for the Lake Road and the La Paloma credit facilities. As of December 4, 2002, PG&E NEG and certain of its subsidiaries entered into agreements with respect to each of the Lake Road and La Paloma generating projects providing for (1) funding of construction costs required to complete the La Paloma facility; and (2) additional working capital facilities to enable each subsidiary to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent transmission system operator requirements, as well as for general working capital purposes. Lenders extending new credit under these agreements have received liens on the projects that are senior to the existing lenders' liens. These agreements provide, among other things, that the failure to transfer right, title and interest in, to and under the Lake Road and La Paloma projects to the respective lenders by June 9, 2003, will constitute a default under the agreements. The failure to transfer the facilities would entitle the lenders to accelerate the new indebtedness and exercise other remedies.

The Lake Road and La Paloma projects have been financed entirely with debt. PG&E NEG has guaranteed the repayment of a portion of the project subsidiary debt of approximately $230 million for Lake Road and $375 million for La Paloma, which amounts represent the subsidiaries' equity contribution in the projects. The lenders have demanded the immediate payment of these equity contributions. Neither the PG&E NEG subsidiaries nor PG&E NEG have sufficient funds to make these payments. The requirement to make the payments will remain an obligation of PG&E NEG that would survive the transfer of the projects.

In accordance with the provisions of SFAS No. 144, the long-lived assets of the Lake Road and La Paloma project subsidiaries at December 31, 2002, were tested for impairment. As a result of the test, these assets were determined to be impaired and were written down to fair value. Based on the current estimated fair value of these assets, the Lake Road and La Paloma project subsidiaries recorded a pre-tax loss from impairment of approximately $186 million and $266 million, respectively, in the fourth quarter of 2002.

Impairment of Mantua Creek Project: The Mantua Creek project is a nominal 897 megawatt (MW) combined cycle merchant power plant located in the Township of West Deptford, New Jersey.

Construction began in October 2001 and the project was 24 percent complete as of October 31, 2002. Due to liquidity concerns, PG&E NEG could no longer provide equity contributions to the project and efforts to sell the project were unsuccessful. Beginning in the fourth quarter of 2002, contracts with vendors were suspended or terminated to eliminate an increase in project costs. In December 2002, the project provided notices of termination to the Pennsylvania, New Jersey, Maryland Independent System Operator (PJM), and other significant counterparties. With all significant contracts terminated, PG&E NEG's subsidiary will abandon this project in early 2003. PG&E NEG's subsidiary has written off the capitalized development and construction costs of $257 million at December 31, 2002. In addition, PG&E NEG has recorded an accrual of $22 million for charges and associated termination costs at December 31, 2002.

Impairment of Turbines and Other Related Equipment: To support PG&E NEG's electric generating development program, PG&E NEG subsidiaries had contractual commitments and options to purchase a significant number of combustion turbines and related equipment. PG&E NEG subsidiaries' commitment to purchase combustion turbines and related equipment exceeded the new planned development activities discussed herein. In the second quarter of 2002, these PG&E NEG subsidiaries recognized a pre-tax charge of $246 million. The charge consisted of the impairment of the previously capitalized costs associated with prior payments made under the terms of the turbine and equipment contracts in the amount of $188 million and an accrual of $58 million for future termination payments required under the turbine and related equipment contracts. In addition, at that time, the PG&E NEG subsidiaries retained capitalized prepayment costs associated with three development projects that were to be further developed or sold. In the fourth quarter of 2002, these PG&E NEG subsidiaries incurred an additional pre-tax charge of $30 million for the write-off of prior turbine prepayments associated with the impairment of the remaining development projects as discussed below.

In November 2002, subsidiaries of PG&E NEG reached agreement with General Electric Company (GEC) to terminate its master turbine purchase agreement and with General Electric International, Inc. (GEII) to terminate its master long-term service agreement. GEC and GEII have agreed to reduce the termination fees from approximately $34 million to approximately $22 million and to defer payment of the reduced fees to December 31, 2004. The costs to terminate this contract were accrued for in the second quarter of 2002 as discussed above.

Also in November 2002, Mitsubishi Power Systems, Inc. (MPS) notified PG&E NEG's subsidiary that it was terminating the turbine purchase agreement for failure to pay past due amounts and failure to collateralize PG&E NEG's guarantee. While PG&E NEG's subsidiary has disputed that such amounts were due before January and July 2003 and has asserted that a breach under PG&E NEG's guarantee did not give rise to a breach of the turbine purchase agreement, neither PG&E NEG nor its subsidiary intends to contest the termination. The costs to terminate this contract were accrued for in the second quarter of 2002, as discussed above. On January 31, 2003, a termination payment of $4.5 million was made with the remaining amount of $9.5 million expected to be paid in July 2003.

Termination of Interest Rate Swaps on Lake Road, La Paloma and GenHoldings Projects: As a result of the Lake Road and La Paloma project subsidiaries' failure to make required equity payments under interest rate hedge contracts entered into by them, the counterparties to such interest rate hedge contracts have terminated the contracts. Settlement amounts due from the Lake Road and La Paloma project subsidiaries in connection with such terminated contracts are, in the aggregate, $61 million and $78 million, respectively. Further, as a result of GenHoldings' failure to make required payments under interest rate hedge contracts entered into by GenHoldings, the counterparties to such interest rate hedge contracts terminated the contracts during December 2002. Settlement amounts due by GenHoldings in connection with such terminated contracts are, in the aggregate, approximately $50 million. The Lake Road and La Paloma project subsidiaries and GenHoldings incurred a pre-tax charge to earnings in the fourth quarter of 2002 for these amounts totaling $189 million.

Impairment of Dispersed Generation: PG&E NEG is seeking a buyer for PG&E Dispersed Generation, LLC, Plains End, LLC, Dispersed Properties, LLC and 100 percent of the capital stock of Ramco Inc, (collectively, referred to as Dispersed Gen Companies or Dispersed Generation). In accordance with the provisions of SFAS No. 144, the long-lived assets of the Dispersed Gen Companies were tested for impairment. As a result of the test, these assets were determined to be impaired and were written down to fair value. Based on the current estimated fair value (based on the estimated proceeds) of a sale, Dispersed Generation recorded a pre-tax loss from impairment of $88 million in the fourth quarter of 2002. This is in addition to a pre-tax loss from impairment of $30 million that was recorded in the third quarter of 2002, which related to certain equipment (turbines, generators, transformers, etc.) that was purchased and/or refurbished and held for future expansion at current Dispersed Generation facilities.

Impairment of Goodwill: SFAS No. 142 "Goodwill and Other Intangible Assets," requires that goodwill be reviewed at least annually for impairment. Due to significant adverse changes within the national energy markets, PG&E NEG and its subsidiaries elected to test its goodwill for possible impairment in the third quarter of 2002. Based upon the results of the fair value test, PG&E NEG and it subsidiaries recognized a goodwill impairment loss of $95 million in the third quarter of 2002. The fair value of the segment was estimated using the discounted cash flows method. At December 31, 2002, there was no goodwill remaining at PG&E NEG and its subsidiaries.

Impairment of Development Costs: In the second quarter of 2002, PG&E NEG project subsidiaries recognized an impairment loss related to the capitalized costs associated with certain development projects. These PG&E NEG subsidiaries analyzed the potential future cash flow from those projects that it no longer anticipated developing and recognized an impairment of the asset value it was carrying for those projects. The aggregate pre-tax impairment charge recorded by these PG&E NEG subsidiaries for its development assets (excluding associated equipment) was $19 million recorded in the second quarter of 2002. At that time, these PG&E NEG subsidiaries continued to develop or planned to sell three additional projects. These subsidiaries have ceased developing these projects and sought to sell the development assets. To date, these subsidiaries have been unsuccessful in selling these projects and have tested the capitalized costs associated with the projects for impairment at December 31, 2002. Based upon the results of these tests, an additional aggregate pre-tax impairment charge of approximately $57 million was recorded by these subsidiaries for their development assets (excluding associated equipment costs as discussed above) in the fourth quarter of 2002. While these subsidiaries have impaired all of their development projects, they have not abandoned the permits or rights to these projects. It is anticipated that these permits and rights will be abandoned for all development projects in 2003.

Impairment of Southaven Power LLC Loan Receivable: PG&E ET signed a tolling agreement with Southaven Power LLC (Southaven) dated June 1, 2000, pursuant to which PG&E ET was required to provide credit support that meets certain requirements set forth in the agreement. PG&E ET satisfied this obligation by providing an investment-grade guarantee from PG&E NEG. The original maximum amount of the guarantee was $250 million. However, this amount was reduced by approximately $74 million, the amount of a subordinated loan that PG&E ET made to Southaven on August 31, 2002.

Southaven has advised PG&E ET that it believes an event of default under the tolling agreement has taken place with respect to the obligation for a guarantee because PG&E NEG is no longer investment- grade as defined in the agreement and because PG&E ET has failed to provide, within 30 days from the downgrade, substitute credit support that meets the requirements of the agreement. Under the tolling agreement, Southaven has the right to terminate the agreement and seek a termination payment. In addition, PG&E ET has provided Southaven with a notice of default with respect to Southaven's performance under the tolling agreement. If this default is not cured, PG&E ET has the right to terminate the agreement and seek recovery of a termination payment. On February 4,

2003, PG&E ET provided a notice of termination. Southaven has objected to the notice and has filed suit in connection with this matter. PG&E ET has recorded an impairment of the loan receivable due to the uncertainty associated with the recoverability of the loan, which was subordinate to the senior debt of the project and reliant upon operations of the plant under the terms of the tolling agreement.

Impairment of Prepaid Rents on Attala Lease: On May 7, 2002, Attala Generating Company LLC (Attala Generating), an indirect wholly owned subsidiary of PG&E NEG, completed a $340 million sale and leaseback transaction whereby it sold and leased back its approximately 526 MW generation facility located in Mississippi to a third-party special purpose entity.

PG&E NEG has provided a $300 million guarantee to support the payment obligations of another indirect wholly owned subsidiary, Attala Energy Company LLC (Attala Energy) under a tolling agreement entered into with Attala Generating. The payments under the 25-year term tolling agreement provide Attala Generating, as lessee, with sufficient cash flows during the term of the tolling agreement to pay rent under a 37-year lease and certain other operating costs. Due to current energy market conditions, Attala Energy is unable to make the payments under the tolling agreement and failed to make the required payment due on November 22, 2002, to Attala Generating. Failure to cure this payment default constituted an event of default under the tolling agreement as of November 27, 2002. Further, PG&E NEG's failure to pay maturing principal under its Corporate Revolver on November 14, 2002, became an event of default under the tolling agreement upon Attala Energy's failure to replace the PG&E NEG guarantee by December 16, 2002. On December 31, 2002, the tolling agreement terminated following notice of termination given by Attala Generating. The parties are currently determining the termination payment, if any, that Attala Energy would owe Attala Generating. Despite the termination of the tolling agreements, Attala Energy remains obligated to provide an acceptable guarantee or collateral to secure its obligations under the tolling agreement, including the payment of any termination payment that may be determined to be due.

No default has occurred under the related lease and Attala Generating timely made the $22.2 million lease payment due on January 2, 2003. However, the lease provides that failure to replace the tolling agreement with a satisfactory replacement tolling agreement within 180 days after the first default under the tolling agreement, which occurred on November 27, 2002, will constitute an event of default under the lease. After the termination payment has been determined in accordance with the tolling agreement and if Attala Energy or PG&E NEG both fail, or have failed, to provide security as required by the tolling agreement, the time period would not extend beyond the 60^{th} day after such failure to provide security. Upon the occurrence of an event of default under the lease, the lessor would be entitled to exercise various remedies, including termination of the lease and foreclosure of the assets securing the lease. At December 31, 2002, Attala Generating wrote-off prepaid rental payments of $43 million due to the uncertainty of future cash flows associated with the lease.

Impairment of Kentucky Hydro Project: The Kentucky Hydro Generating Project consists of two run-of-river hydroelectric power plants located in Kentucky on the Ohio River. The project negotiated a turnkey, fixed price contract with VA Tech MCE Corporation (VA Tech) and issued a limited notice to proceed in August 2001. Beginning in the fourth quarter of 2002, all work on the project was suspended except for minimal expenditures to maintain the FERC licenses. The termination cost due to VA Tech of approximately $14 million was fully paid. VA Tech terminated the contract effective December 6, 2002. As part of the settlement of PG&E NEG subsidiary's partnership arrangement, this subsidiary assigned its partnership interest to the original developer, W.V. Hydro, on February 7, 2003. PG&E NEG has written-off the capitalized development and construction costs and provided for all termination costs by recording a pre-tax charge of $18 million at December 31, 2002.

Asset Held For Sale U.S. Gen New England: Consistent with its previously announced strategy to dispose of certain merchant assets, in December 2002, the Board of Directors of PG&E Corporation approved management's plan for the proposed sale of USGen New England Inc. (USGenNE). Under

the provisions of SFAS No. 144, the equity of USGenNE has been accounted for as an asset held for sale at December 31, 2002. This requires that the assets be recorded at the lower of fair or book value. Based on the current estimated fair value (based on the estimated proceeds) of a sale of USGenNE, a pre-tax loss of $1.1 billion, with no tax benefits associated with the loss, was recorded in the fourth quarter of 2002. It is anticipated that the sale of the USGenNE assets will occur during 2003. This loss on sale, as well as the operating results from USGenNE, have been reported as discontinued operations in the financial statements of PG&E NEG and subsidiaries at December 31, 2002.

Assets Held for Sale ET Canada: In December 2002, the proposed sale of PG&E Energy Trading, Canada Corporation (ET Canada) to Seminole Gas Company Limited was approved. Based upon the sales price, PG&E Energy Trading Holdings Corporation, the direct owner of the shares of ET Canada, recorded a $25 million pre-tax loss, with no tax benefits associated with the loss, on the disposition of ET Canada. The transaction is anticipated to close by the end of February or early March 2003. In accordance with the provisions of SFAS No. 144, the equity of ET Canada has been classified as assets held for sale and will be reflected as discontinued operations in the financial statements of PG&E NEG and subsidiaries as of December 31, 2002.

COMMITMENTS AND CAPITAL EXPENDITURES

The following table provides information about PG&E Corporation, the Utility and PG&E NEG's contractual obligations and commitments at December 31, 2002.

(Dollars in millions)

	2003	2004	2005	2006	2007	Thereafter
Utility:						
Power purchase agreements	$ 1,984	$ 1,701	$ 1,544	$ 1,446	$ 1,377	$ 8,492
Natural gas supply and transportation	595	138	83	26	10	
Nuclear fuel	59	50	12	13	14	65
Other Commitments	60	45	39	24	11	11
Long-term debt:						
Liabilities not subject to compromise:						
Fixed rate principal obligations	281	310	290			2,139
Average interest rate	6.25%	6.25%	5.88%			7.25%
Liabilities subject to compromise:						
Fixed rate principal obligations	173	54	696	1	1	261
Average interest rate	7.40%	7.51%	9.56%	9.45%	9.45%	5.95%
7.90 Percent Deferrable Interest Subordinated Debentures						300
Variable rate principal obligations	349	265				
Rate reduction bonds	290	290	290	290	290	
Average interest rate	6.36%	6.42%	6.42%	6.44%	6.48%	
PG&E NEG:						
Fuel supply and natural gas transportation agreements	105	91	91	88	75	380
Power purchase agreement	217	220	220	220	225	1,140
Operating leases	70	79	79	81	84	807
Long-Term Service Agreements	41	7	7	7	7	36
Payment in lieu of taxes	28	21	14	16	17	97
Construction commitments	237					
Tolling agreements	62	62	62	62	62	482
Long-term debt:						
Fixed rate obligations	6		250			250
Variable rate obligations	86	3	60	52	4	11
Average interest rate	6.41%	6.57%	6.92%	7.33%	7.31%	7.10%
PG&E Corporation:						
Long-term debt:						
Fixed rate obligations (9.50% Convertible Subordinated Notes)						280
Average interest rate						9.50%
Variable rate[1]				842		

(1) $720 million outstanding at December 31, 2002, with 4 percent interest compounded yields value of $842 million at maturity.

Utility

The Utility's contractual commitments include natural gas supply and transportation agreements, purchase power agreements (including agreements with QFs, irrigation districts and water agencies, bilateral power purchase contracts, and renewable energy contracts), nuclear fuel agreements, operating leases and other commitments.

The Utility's commitments under financing arrangements include obligations to repay first and refunding mortgage bonds, senior notes, medium-term notes, pollution control loan agreements, Deferrable Interest Subordinated Dedentures, lines of credit, letters of credit, floating rate notes, and commercial paper.

PG&E Funding LLC, a wholly owned subsidiary of the Utility is also obligated to make scheduled principal payments on its rate reduction bonds.

For further detailed discussion of the Utility's contractual commitments and obligations, see Notes 4, 5, and 16 of the Notes to the Consolidated Financial Statements.

PG&E NEG

PG&E NEG subsidiaries have the following contractual commitments:

Fuel Supply and Transportation Agreements PG&E NEG, through its various subsidiaries, has entered into gas supply and firm transportation agreements with a number of pipelines and fuel transportation services. Under these agreements, PG&E NEG's subsidiaries must make specified minimum payments each month.

Power Purchase Agreements 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 assets. As of December 31, 2002, these agreements provided for an aggregate of approximately 800 MW of capacity. USGenNE is required to pay New England Power Company amounts due to third-party producers under the power purchase contracts.

Operating Leases Various subsidiaries of PG&E NEG entered into several operating lease agreements for generating facilities and office space. Lease terms vary between 3 and 48 years.

In November 1998, USGenNE entered into a $479 million sale-leaseback transaction whereby the subsidiary sold and leased back a pumped storage station under an operating lease.

On May 7, 2002, Attala Generating completed a $340 million sale and leaseback transaction whereby it sold and leased back its facility to a third party special purpose entity. The related lease is being accounted for as an operating lease. See discussion above for further information relating to the Attala lease agreement.

Operating lease expense amounted to $78 million, $54 million, and $70 million in 2002, 2001, and 2000, respectively.

Long-Term Service Agreements Various subsidiaries of PG&E NEG have entered into long-term service agreements for the maintenance and repair of certain combustion turbine or combined-cycle generating plants. These agreements are for periods up to 18 years.

Payments in Lieu of Property Taxes Various subsidiaries of PG&E NEG have entered into certain agreements with local governments that provide for payments in lieu of property taxes for some of its generating facilities.

Construction Commitments Various subsidiaries of PG&E NEG currently have four projects (Athens, Covert, La Paloma, and Harquahala) under construction. PG&E NEG's construction commitments are generally related to the major construction agreements including the construction and other related contracts. Certain construction contracts also contain commitments to purchase turbines and related equipment.

Tolling Agreements PG&E ET entered into tolling agreements with several counterparties allowing PG&E NEG the right to sell electricity generated by facilities owned and operated by other parties. Under the tolling agreements, PG&E NEG, at its discretion, supplies the fuel to the power plants, 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. See Tolling Agreements below for additional information relating to these agreements.

Guarantees

PG&E NEG's and its subsidiaries' guarantees fall into four broad categories:

- Equity commitments;
- PG&E ET's energy trading and non-trading activities related to PG&E NEG's merchant energy portfolio excluding tolling agreements;
- Tolling agreements; and
- Other guarantees.

Equity Commitments: Refer to discussion above on impairments under "Market Conditions and Business Environment."

Activities Related to Merchant Portfolio Operations: PG&E NEG and certain subsidiaries have provided guarantees to approximately 232 counterparties in support of PG&E ET's energy trading and non-trading activities related to PG&E NEG's merchant energy portfolio in the face amount of $2.7 billion. Typically, the overall exposure under these guarantees is only a fraction of the face value of these guarantees, since not all counterparty credit limits are fully used at any time. As of January 31, 2003, PG&E NEG and its subsidiaries' aggregate exposure under these guarantees was approximately $82.8 million. The amount of such exposure varies daily depending on changes in market prices and net changes in position. In light of the downgrades, some counterparties have sought and others may seek replacement security to collateralize the exposure guaranteed by PG&E NEG and its subsidiaries. PG&E GTN and PG&E ET have terminated the arrangements pursuant to which PG&E GTN provided guarantees on behalf of PG&E ET such that PG&E GTN will provide no new guarantees on behalf of PG&E ET.

At January 31, 2003, PG&E ET's estimated exposure not covered by a guarantee (excluding exposure under tolling agreements) was approximately $90 million.

To date, PG&E ET has met those replacement security requirements properly demanded by counterparties and has not defaulted under any of its master trading agreements although one counterparty has alleged a default. No demands have been made upon the guarantors of PG&E ET's obligations under these trading agreements. In the past, PG&E ET has been able to negotiate acceptable arrangements and reduce its overall exposure to counterparties when PG&E ET or its counterparties have faced similar situations. There can be no assurance that PG&E ET can continue to negotiate acceptable arrangements in the current circumstances. PG&E NEG cannot quantify with any certainty the actual future calls on PG&E ET's liquidity. PG&E NEG's and its subsidiaries' ability to meet these calls on their liquidity will vary with market price volatility, uncertainty with respect to PG&E NEG's financial condition and the degree of liquidity in the energy markets. The actual calls for collateral will depend largely upon the ability to enter into forbearance agreements, and pre- and early-pay arrangements with counterparties, the continued performance of PG&E NEG companies under the underlying agreements, whether counterparties have the right to demand such collateral, the execution of master netting agreements and offsetting transactions, changes in the amount of exposure, and other commercial considerations.

Tolling Agreements: PG&E ET has entered into tolling agreements with several counterparties under which it, at its discretion, supplies the fuel to the power plants and then sells the plant's output in the competitive market. Payments to the counterparties are reduced if the plant's do not achieve agreed-upon levels of performance. The face amount of PG&E NEG's and its subsidiaries' guarantees relating to PG&E ET's tolling agreements is approximately $600 million. The tolling agreements currently in place are with: (1) Liberty Electric Power, L.P. (Liberty) guaranteed primarily by PG&E NEG and secondarily by PG&E GTN for an aggregate amount of up to $150 million;
(2) DTE-Georgetown, LLC (DTE) guaranteed by PG&E GTN for up to $24 million; (3) Calpine Energy Services, L.P. (Calpine) for which no guarantee is in place; (4) Southaven guaranteed by PG&E NEG for up to $175 million; and (5) Caledonia Generating, LLC (Caledonia) guaranteed by PG&E NEG for up to $250 million.

Liberty Liberty has provided notice to PG&E ET that the ratings downgrade of PG&E NEG constituted a material adverse change under the tolling agreement requiring PG&E ET to replace the guarantee and post security in the amount of $150 million. PG&E ET has not posted such security. Liberty has the right to terminate the agreement and seek recovery of a termination payment. Under the terms of the guarantees to

Liberty for the aggregate $150 million, Liberty must first proceed against PG&E NEG's guarantee, and can demand payment under PG&E GTN's guarantee only if (1) PG&E NEG is in bankruptcy or (2) Liberty has made a payment demand on PG&E NEG which remains unpaid five business days after the payment demand is made. In addition, PG&E ET has provided notices to Liberty of several breaches of the tolling agreement by Liberty and has advised Liberty that, unless cured, these breaches would constitute a default under the agreement. If these defaults remain uncured, PG&E ET has the right to terminate the agreement and seek recovery of a termination payment.

DTE By letter dated October 14, 2002, DTE provided notice to PG&E ET that the downgrade of PG&E GTN constituted a material adverse change under the tolling agreement between PG&E ET and DTE and that PG&E ET was required to post replacement security within ten days. By letter dated October 23, 2002, PG&E ET advised DTE that because there had not been a material adverse change with respect to PG&E GTN within the meaning of the tolling agreement, PG&E ET was not required to post replacement security. If PG&E ET was required to post replacement security and it failed to do so, DTE would have the right to terminate the tolling agreement and seek recovery of a termination payment.

Calpine The tolling agreement states that on or before October 15, 2002, Calpine was to have issued a full notice to proceed under its construction contract to its engineering, procurement and construction contractor for the Otay Mesa facility. On October 16, 2002, PG&E ET asked Calpine to confirm that it had issued this full notice to proceed and Calpine was not able to do so to the satisfaction of PG&E ET. Consequently, PG&E ET advised Calpine by letter dated October 30, 2002, that it was terminating the tolling agreement effective November 29, 2002. Calpine has indicated that this termination was improper and constituted a default under the agreement, but has not taken any further action.

Caledonia and Southaven New Tolling Agreements PG&E ET signed a tolling agreement with Caledonia dated as of September 20, 2000, pursuant to which PG&E ET is to provide credit support as defined in the tolling agreement. PG&E ET satisfied this obligation by providing a guarantee from PG&E NEG that was investment-grade as defined in the agreement. The amount of the guarantee now does not exceed $250 million. By letter dated August 31, 2002, Caledonia advised PG&E ET that it believed an event of default under the tolling agreement had taken place with respect to this obligation as PG&E NEG was no longer investment-grade as defined in the tolling agreement and because PG&E ET had failed to provide, within thirty days from the downgrade substitute credit support that met the requirements of the tolling agreement. Caledonia has the right to terminate the agreement and seek a

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termination payment. In addition, PG&E ET has provided Caledonia with a notice of default respecting Caledonia's performance under the tolling agreement concerning the inability of the facility to inject its output into the local grid. Caledonia has not cured this default and on February 4, 2003, PG&E ET provided a notice of termination.

PG&E ET signed a tolling agreement with Southaven dated as of June 1, 2000, under which PG&E ET is required to provide credit support as defined in the agreement. PG&E ET satisfied this obligation by providing an investment-grade guarantee from PG&E NEG as defined in the tolling agreement. The amount of the guarantee is approximately $175 million. By letter dated August 31, 2002, Southaven advised PG&E ET that it believed an event of default under the tolling agreement had taken place as PG&E NEG was no longer investment-grade as defined in the tolling agreement and because PG&E ET had failed to provide, within thirty days from the downgrade, substitute credit support that met the requirement of the tolling agreement. Southaven has the right to terminate the agreement and seek a termination payment. In addition, PG&E ET has provided Southaven with a notice of default respecting Southaven's performance under the tolling agreement concerning the inability of the facility to inject its output into the local grid. Southaven has not cured this default and on February 4, 2003, PG&E ET provided a notice of termination.

On February 7, 2003, Southaven filed emergency petitions to compel arbitration or alternatively, a temporary restraining order and preliminary injunction with the Circuit Court for Montgomery County, Maryland. The Court has denied the relief requested and has set the matter for hearing on February 27, 2003.

PG&E ET is not able to predict whether the counterparties will seek to terminate the agreements or whether the Court will grant the requested relief. Accordingly, it is not able to predict whether or the extent to which these proceedings will have a material adverse effect on PG&E NEG's financial condition or results of operation.

Under each tolling agreement determination of the termination payment is based on a formula that takes into account a number of factors including market conditions such as the price of power and the price of fuel. In the event of a dispute over the amount of any termination payment that the parties are unable to resolve by negotiation, the tolling agreement provides for mandatory arbitration. The dispute resolution process could take as long as six months to more than a year to complete. To the extent that PG&E ET did not pay these damages, the counterparties could seek payment under the guarantees for an aggregate amount not to exceed $600 million. PG&E NEG is unable to predict whether counterparties will seek to terminate their tolling agreements. PG&E NEG does not currently expect to be able to pay any termination payments that may become due.

Other Guarantees

PG&E NEG has provided guarantees related to other obligations by PG&E NEG companies to counterparties for goods or services. PG&E NEG does not believe that it has significant exposure under these guarantees. The most significant of these guarantees relate to performance under certain construction and equipment procurement contracts. In the event PG&E NEG is unable to provide any additional or replacement security which may be required as a result of rating downgrades, the counterparty providing the goods or services could suspend performance or terminate the underlying agreement and seek recovery of damages. These guarantees represent guarantees of subsidiary obligations for transactions entered into in the ordinary course of business. Some of the guarantees relate to the construction or development of PG&E NEG's power plants and pipelines. These guarantees are described below.

PG&E NEG has issued guarantees for the performance of the contractors building the Harquahala and Covert power projects for up to $555 million. Any exposure under the guarantees for construction completion is mitigated by guarantees in favor of PG&E NEG from the constructor and equipment

vendors related to performance, schedule, and cost. The constructor and various equipment vendors are performing under their underlying contracts.

PG&E NEG has issued $100 million of guarantees to the constructor of the Harquahala and Covert projects to cover certain separate cost-sharing arrangements. Failure to perform under those separate cost-sharing arrangements or the related guarantees would not have an impact on the constructor's obligations to complete the Harquahala and Covert projects pursuant to the construction contracts. However, in the event that the construction contractor incurs certain un-reimbursed project costs or cost overruns, the contractor could assert a claim against PG&E NEG's subsidiary or PG&E NEG under its guarantees. PG&E NEG believes that no claim can be validly asserted by the construction contractor as of the date hereof.

PG&E NEG has provided a $300 million guarantee to support a tolling agreement that a wholly owned subsidiary, Attala Energy, has entered into with Attala Generating. See discussion above under "Impairment of Prepaid Rents on Attala Lease," for additional discussion of this guarantee.

In addition to those discussed above, PG&E NEG has guarantees for commitments undertaken by PG&E NEG or subsidiaries in the ordinary course of business for services such as facility and equipment leases, ash disposal rights, and surety bonds.

Credit Facility Summary:

PG&E NEG has the following credit facilities outstanding at January 31, 2003:

(in millions)	**Total Bank Commitment**	**Balance**
PG&E NEG Inc. Tranche A (2 year facility)[a]	$ 264	$ 264
PG&E NEG Inc. Tranche B (364 day facility)[a]	431	431
PG&E ETH and Subsidiaries Facility One	35	34
PG&E ETH and Subsidiaries Facility Two	19	19
PG&E Generating LLC	7	7
USGen New England	100	88
PG&E GTC and Subsidiaries	125	53
Total	$ 981	$ 896

(a) PG&E NEG is currently in default on both its Tranche A and Tranche B credit facility.

PG&E CORPORATION

Due to the Utility's deteriorating liquidity and financial condition during the California energy crisis in 2000, PG&E Corporation refinanced its debt obligations through a credit agreement (Original Credit Agreement) with General Electric Capital Corporation (GECC) and Lehman Commercial Paper Inc. (LCPI) in 2001. The proceeds of this refinancing were used to pay commercial paper, borrowings under PG&E Corporation's long-term revolving credit facility, and a fourth quarter 2000 dividend to shareholders. During 2002, PG&E Corporation negotiated new terms to amend the Original Credit Agreement. In August 2002, PG&E Corporation made a voluntary prepayment of principal and interest totaling $607 million to the GECC portion of the debt.

On October 18, 2002, PG&E Corporation entered into a Second Amended Credit Agreement (Credit Agreement) with the remaining lenders for a total amount of $720 million. Of the total amount secured under the Credit Agreement, $420 million covered amounts retained under the prior credit agreement and $300 million represented new loans (New Loans and collectively referred to as the

Loans). These New Loans were released from a separate escrow account to PG&E Corporation on January 17, 2003, concurrent with a funding fee payment of $9 million.

All obligations of PG&E Corporation under the Credit Agreement are secured by a perfected first-priority security interest in the outstanding common stock of the Utility and all proceeds thereof. With respect to 35 percent of such common stock pledged for the benefit of the lenders, the lenders have customary rights of a secured creditor, provided that certain regulatory approvals may be required in connection with any foreclosure on such stock. With respect to the remaining 65 percent, such common stock has been pledged for the benefit of the lenders, but the lenders have no ability to control such common stock under any circumstances and do not have any of the typical rights and remedies of a secured creditor. However, the lenders do have the right to receive any cash proceeds received upon a disposition of such common stock.

All obligations of PG&E Corporation under the Credit Agreement continue to be secured by a perfected first priority security interest in 100 percent of the equity interests in PG&E NEG LLC and 100 percent of the common stock of PG&E NEG and all proceeds thereof.

The Credit Agreement limits the ability of PG&E Corporation and some of its subsidiaries to grant liens, consolidate, merge, purchase or sell assets, declare or pay dividends, incur indebtedness, or make advances, loans, and investments. In addition, PG&E Corporation may not use the proceeds of the New Loans to make investments in PG&E NEG LLC or PG&E NEG, or any of their subsidiaries or, in the Utility, except as specifically permitted by the terms of the loans or as required by applicable law or the conditions adopted by the CPUC with respect to holding companies. However, the Credit Agreement generally permits:

- PG&E NEG LLC, PG&E NEG, and their respective subsidiaries to enter into sales and other dispositions of assets in the ordinary course of business and in certain qualified transactions;
- PG&E Corporation to use existing cash to make investments in PG&E NEG (limited to 75 percent of the net cash tax savings actually received by PG&E Corporation from certain PG&E NEG transactions after October 1, 2002) in connection with certain sales and debt restructuring transactions of PG&E NEG and its subsidiaries;
- PG&E Corporation to make investments funded from existing cash, and to pay obligations of PG&E NEG and its subsidiaries (including, without limitation, any obligations for which PG&E Corporation becomes a surety or a guarantor) up to a cumulative amount not to exceed $15 million;
- PG&E NEG LLC, PG&E NEG, or their respective subsidiaries to grant liens or incur debt;
- PG&E Corporation and the Utility to consummate the transactions contemplated in the Utility's Plan; and

PG&E Corporation to spin off 100 percent of the equity interests in PG&E NEG LLC and 100 percent of the common stock of PG&E NEG, and all proceeds thereof, with the consent of lenders holding more than 50.1 percent of the aggregate outstanding principal amount of the Loans.

The Credit Agreement provides for stated events of default and events requiring mandatory prepayment of the Loans. See Note 4 of the Notes to the Consolidated Financial Statements for further discussion of the Credit Agreement.

In connection with the Utility's proposed plan of reorganization, PG&E Corporation intends to negotiate with the lenders to obtain their consent to the issuance of up to $700 million of PG&E Corporation equity and the contribution of some of the proceeds of issuance to the capital of the Utility.

In connection with the Credit Agreement, PG&E Corporation also has issued to the lenders additional warrants to purchase 2,669,390 shares of common stock of PG&E Corporation, with an exercise price of $0.01 per share. PG&E Corporation has agreed to provide, following consummation of a plan of reorganization of the Utility, registration rights in connection with the shares issuable upon exercise of these warrants.

The net proceeds of the Loans will be used to fund corporate working capital and for general corporate purposes.

PG&E Corporation's Convertible Subordinated Notes (Notes) in the aggregate principal amount of $280 million were issued on June 25, 2002.

The Notes, maturing on June 30, 2010, have an interest rate of 9.50 percent, and provide the holder of the Notes with a one-time right to require PG&E Corporation to repurchase the Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including any liquidated damages and pass-through dividends).

CASH FLOWS

Utility

The following section discusses the Utility's significant cash flows from operating, investing, and financing activities for the years ended December 31, 2002, 2001, and 2000.

Operating Activities

Results from the Utility's consolidated cash flows from operating activities for the years ended 2002, 2001, and 2000 are as follows:

(in millions)	**Year ended December 31,**		
	2002	**2001**	**2000**
Net income (loss)	$ 1,819	$ 1,015	$ (3,483)
Depreciation, amortization, and decommissioning included in net income	1,193	896	3,511
Reversal of ISO accrual included in net income	(970)		
Increase in accounts payable	198	1,312	3,063
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	(1,442)	(16)	
(Increase) Decrease in income taxes receivable	(50)	1,120	(1,120)
Other operating activity adjustments	386	438	(1,416)

(in millions)	Year ended December 31,		
Net cash provided by operating activities	$ 1,134	$ 4,765	$ 555

Operating activities provided net cash of $1.1 billion in 2002 and $4.8 billion in 2001. The decrease during the period is primarily due to the following factors:

The Utility filed for bankruptcy in April 2001, which automatically stayed all payments on liabilities incurred prior to the bankruptcy. Subsequent to the bankruptcy, the Utility resumed paying its ongoing expenses in the ordinary course of business. As a result, the growth in accounts payable is $1.1 billion lower in 2002 compared to 2001;

The Utility received a $1.1 billion income tax refund in 2001; no comparable refund was received in 2002;

In 2002, approximately $901 million in principal owed to QFs prior to the bankruptcy was repaid by the Utility under Bankruptcy Court approved agreements. Among other things, the

agreements provided for repayments of amounts owed to QFs prior to the bankruptcy either in full or in 6 to 12 monthly installments; and

In 2002, the Bankruptcy Court issued an order authorizing the Utility to pay pre- and post-petition interest to:

1. Holders of certain undisputed claims, including commercial paper, senior notes, floating rate notes, medium-term notes, Deferrable Interest Subordinated Debentures (QUIDS), prior bond claims, revolving line of credit claims, and secured debt claims;

2. Trade creditors, including QFs; and

3. Certain other general unsecured creditors.

The Utility paid approximately $1 billion in pre- and post-petition interest related to these claims during 2002. The interest payments included accrued interest on financial debt previously classified as liabilities subject to compromise totaling $433 million.

Operating activities provided net cash of $4.8 billion in 2001 and $0.6 billion in 2000. The increase in 2001 was primarily due to an increase in net income and the receipt of a $1.1 billion income tax refund in 2001. Of the $4.5 billion increase in net income, $2.6 billion was attributable to a decrease in depreciation, a non-cash expense. See the Results of Operations section of this MD&A for a discussion of the Utility's net income.

Investing Activities

Results from the Utility's consolidated cash flows from investing activities for the years ended 2002, 2001, and 2000 are as follows:

(in millions)	Year ended December 31,		
	2002	**2001**	**2000**
Capital expenditures	$ (1,546)	$ (1,343)	$ (1,245)
Other investing activities	37	5	38

(in millions)	Year ended December 31,		
Net cash used by investing activities	$ (1,509)	$ (1,338)	$ (1,207)

Cash used by investing activities in 2002, 2001, and 2000, was primarily for capital expenditures related to improvements to the Utility's electricity and natural gas transmission and distribution systems.

While the Utility is in bankruptcy, capital expenditures are being funded with cash provided by operating activities.

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Financing Activities

Results from the Utility's consolidated cash flows from financing activities for the years ended 2002, 2001, and 2000 are as follows:

(in millions)	Year ended December 31,		
	2002	2001	2000
Net (repayments) borrowings under credit facilities and short-term borrowings	$	$ (28)	$ 2,630
Net, long-term debt issued, matured, redeemed, or repurchased	(333)	(111)	373
Rate reduction bonds matured	(290)	(290)	(290)
Common stock repurchased			(275)
Dividends paid			(475)
Other financing activities		(1)	(26)
Net cash provided (used) by financing activities	$ (623)	$ (430)	$ 1,937

Except as contemplated in the Utility's proposed plan of reorganization discussed in Note 2 of the Notes to the Consolidated Financial Statements, the Utility has no plans to seek external financing as a source of funding. Additionally, the Utility is not allowed to pay dividends on its preferred or common stock while in bankruptcy without Bankruptcy Court approval. As discussed in Note 9 and 10 of the Notes to the Consolidated Financial Statements, the Utility did not declare or pay common and preferred stock dividends in 2001 or 2002. Preferred stock dividends have a cumulative feature in which preferred stock dividends must be brought current before any dividends can be distributed to common stockholders. Further, the preferred stocks have a mandatory sinking fund feature in which funds are set-aside for the future periodic retirement of outstanding preferred stock. Until cumulative dividend payments on the Utility's preferred stock and mandatory sinking fund payments are made, the Utility may not pay dividends on its common stock. See Note 10 of the Notes to the Consolidated Financial Statements for a discussion of the Utility's preferred stock.

2002

Financing activities used $623 million of net cash in 2002 primarily reflecting the repayments of long-term debt and rate reduction bonds. Pursuant to Bankruptcy Court approval, the Utility repaid $333 million in principal on its mortgage bonds that matured in March 2002. PG&E Funding LLC, a wholly owned subsidiary of the Utility, also repaid $290 million in principal on its rate reduction bonds during 2002. PG&E Funding LLC and the rate reduction bonds are not included in the Utility's bankruptcy.

2001

Financing activities used $430 million of net cash in 2001 primarily for repayments of long-term debt and rate reduction bonds. The repayment of long-term debt included payments on:

(in millions)

(in millions)

Medium-term notes	$	18
Mortgage bonds		93
Net repayment of long-term debt	$	111

The payments on the medium-term notes and the mortgage bonds were made before the Utility's April 2001 bankruptcy filing.

PG&E Funding LLC repaid $290 million in principal on its rate reduction bonds during 2001. As previously mentioned, the rate reduction bonds are not included in the Utility's bankruptcy.

2000

Financing activities provided $1.9 billion of net cash in 2000 primarily due to borrowings under credit facilities and short-term borrowings, partially offset by (1) principal payments on long-term debt and rate reduction bonds, (2) common stock repurchases, and (3) dividend payments. Net borrowings under credit facilities and short-term borrowings included the following:

(in millions)

Credit facility draws	$	614
Commercial paper issuance		776
364-day floating rate notes issuance		1,240
Net borrowings under credit facilities and short-term borrowings	$	2,630

The Utility issued, repaid, redeemed, or repurchased long-term debt as follows:

(in millions)

Issuance of:		
Senior notes	$	680
Maturity of:		
Mortgage bonds		(110)
Various medium-term notes		(113)
Other long-term debt		(3)
Repurchase of:		
Various pollution control loan agreements		(81)
Net issuance, repayment, redemption, and repurchase of long-term debt	$	373

PG&E Funding LLC repaid $290 million in principal on its rate reduction bonds during 2000.

As previously mentioned, the rate reduction bonds are not included in the Utility's bankruptcy.

In April 2000, a subsidiary of the Utility repurchased 11.9 million shares of the Utility's common stock from PG&E Corporation at a cost of $275 million. The repurchase was made so that the Utility could maintain its CPUC-authorized capital structure, which is the level of common and preferred equity the Utility may maintain in relation to debt.

PG&E NEG

The cash from operations for the years 2002, 2001, and 2000 will not be indicative of the future cash flow from operations due to the changes in the operations of PG&E NEG (discussed above).

To the extent that the commitments of PG&E NEG and its subsidiaries can be restructured, future cash from operations will be principally generated by the PG&E NEG pipeline business as well as dividends from PG&E NEG's independent power producer generation project companies which are accounted for under the equity method of accounting. If the commitments are not restructured, PG&E NEG and its subsidiaries will not generate sufficient funds to meet its outstanding cash requirements and may file or be forced into bankruptcy.

In addition to the impacts of PG&E NEG's downgrades, PG&E NEG's and its subsidiaries' ability to service these obligations is impacted by constraints on the ability to move cash from one subsidiary to another or to PG&E NEG itself. PG&E NEG's subsidiaries must now independently determine, in light of each company's financial situation, whether any proposed dividend, distribution or intercompany loan is permitted and is in such subsidiary's interest. Therefore, Consolidated Statements of Cash Flow and Consolidated Balance Sheets quantifying PG&E NEG's cash and cash equivalents do

not reflect the cash actually available to PG&E NEG or any particular subsidiary to meet its obligations.

At January 31, 2003, PG&E NEG and its subsidiaries had the following unrestricted cash and short-term investment balances (not including in-transit items):

(in millions)

PG&E NEG	$ 126
PG&E ET and Subsidiaries	98
PG&E Gen and Subsidiaries	97
PG&E GTN and Subsidiaries	17
Other	60
Consolidated PG&E NEG	$ 398

Operating Activities

Results from PG&E NEG's consolidated cash flows from operating activities for the years ended 2002, 2001, and 2000 are as follows on a summarized basis:

(in millions)

	2002	2001	2000
Net income (loss)	$ (3,423)	$ 171	$ 152
Adjustments to reconcile net income to net cash (used) provided by operating activities before price risk management assets and liabilities	3,539	(38)	119
Subtotal	116	133	271
Price risk management assets and liabilities, net	99	130	(21)
Net effect of changes in operating assets and liabilities:			
Restricted cash	(62)	(62)	3
Net, accounts receivable, accounts payable and accrued liabilities	100	42	65
Inventories, prepaids, deposits and other	(471)	143	(154)

(in millions)

	2002	2001	2000
Net cash provided (used) by operating activities	$ (218)	$ 386	$ 164

During 2002, PG&E NEG used net cash from operating activities of $218 million. Net cash from operating activities before changes in operating assets and liabilities and price risk management assets and liabilities was $116 million in 2002, created principally from results of operations offset by the timing of deferred tax benefits and lower distributions from unconsolidated affiliates. Change in price risk management assets and liabilities increased cash flow by $99 million due to realization of cash from price risk management activities. The change in inventories, prepaid expenses, deposits, and other liabilities decreased cash flow by $471 million primarily due to increased credit collateral deposit requirements in PG&E NEG's trading operations. Adding to these cash outflows were $62 million of increased in restricted cash requirements.

During 2001, PG&E NEG generated net cash from operating activities of $386 million. Net cash from operating activities before changes in operating assets and liabilities and price risk management assets and liabilities was $133 million in 2001, created principally from results of operations offset by the timing of deferred tax benefits and lower distributions from unconsolidated affiliates. Change in price risk management assets and liabilities increased cash flow by $130 million due to realization of cash from price risk management activities. PG&E NEG's net cash inflow related to the change in accounts receivable, accounts payable, and accrued liabilities from operations assets and liabilities in $42 million. The change in inventories, prepaid expenses, deposits, and other liabilities increased cash flow by $143 million primarily due to repayments of margin deposits in PG&E NEG's trading

operations. Offsetting these cash inflows were $62 million of increased restricted cash requirements in several of PG&E NEG's projects in construction.

During 2000, PG&E NEG generated net cash from operating activities of $164 million. Net cash from operating activities before changes in operating assets and liabilities and price risk management assets and liabilities was $271 million in 2000, created principally from the timing of deferred tax benefits and higher distributions from unconsolidated affiliates.

Change in price risk management assets and liabilities decreased cash flow by $21 million. PG&E NEG's net cash inflow related to the change in accounts receivables, accounts payable, and accrued liabilities increased cash flow by $65 million. The change in inventories, prepaid expenses, deposits, and other liabilities decreased cash flow by $154 million principally due to increased margin deposits in PG&E NEG's trading operations.

Investing Activities

The cash outflows from investing activities for the years 2002, 2001, and 2000 will not be indicative of the future cash outflow from investing activities due to the changes in the operations of PG&E NEG (discussed above). Depending on the results of the restructuring negotiations discussed above, it is anticipated that future cash outflows from investing operations will be principally generated by our pipeline business principally related to maintenance capital expenditures.

Results from PG&E NEG's consolidated cash flows from investing activities for the years ended 2002, 2001, and 2000 are as follows:

(in millions)

	2002	2001	2000
Capital expenditures	$ (1,485)	$ (1,426)	$ (900)
Acquisition of generating assets		(107)	(311)
Proceeds from sale of assets (equity investments)	46		442
Proceeds from sale leaseback	340		
Long-term prepayment on turbines	(15)	(89)	(132)
Investment in Southaven project	(74)		
Repayment of note receivable from PG&E Corporation	75		
Long-term receivable	136	81	75
Other, net	(63)	7	(38)

(in millions)

	2002	2001	2000
Net cash used in investing activities	$ (1,040)	$ (1,534)	$ (864)

Total capital expenditures detailed by business segment and expenditure amount associated with construction work in progress for the year ended 2002, 2001, and 2000 are as follows:

(in millions)

	2002	2001	2000
Capital expenditure by business segment:			
Integrated energy and marketing activities	$ 1,294	$ 1,324	$ 885
Interstate pipeline operations	191	102	15
Total capital expenditures	$ 1,485	$ 1,426	$ 900
Expenditure associated with construction work in progress	$ 1,353	$ 1,318	$ 722

During 2002, PG&E NEG used net cash of $1,040 million in investing activities compared to $1,534 million for the same period in 2001, or a decrease of $494 million. The decrease in cash used in investing activities from period to period was primarily due to proceeds from the Attala Generating sale leaseback transaction providing $340 million, proceeds of $46 million from the partial sale of PG&E NEG's interest in Hermiston and the repayment of a $75 million loan from PG&E Corporation

to PG&E GTN. Offsetting these proceeds were capital expenditures of $1,485 million in 2002 versus $1,426 million in 2001. These capital expenditures were used primarily for construction work in progress and were financed by non-recourse debt. Due to PG&E NEG's default on making equity commitments, these construction projects will potentially be transferred to lenders in 2003. Advanced development and turbine prepayments were $74 million less in 2002 versus 2001 due to the reductions and cancellations of new construction efforts. All remaining development assets and related turbine and other equipments contracts will be abandoned and terminated during 2003. As a result of investment downgrades, PG&E ET replaced a $74 million letter of credit issued to Southaven with cash pursuant to a subordinated loan agreement. No such activity occurred in 2001.

Included in investing activities for 2002 and 2001, are cash flows of $136 million and $81 million respectively related to the long-term receivable from New England Power Company (NEPC) associated with the assumption of power purchase agreements. These cash flows offset cash payments made to NEPC which are reflected in operating activities. PG&E NEG intends to sell USGenNE in 2003.

During 2001, PG&E NEG used net cash of $1.5 billion for investing activities, which were primarily attributable to capital expenditures associated with generating projects in construction, its purchase of the Mountain View wind project, and prepayments on turbines and related equipment.

During 2000, PG&E NEG used net cash of $864 million for investing activities. The primary cash outflows from investing activities were for capital expenditures associated with generating projects in construction, the acquisition of Attala, and prepayments on the turbines and related equipment. These outflows were partially offset by the receipt of $442 million in proceeds from sales of assets and equity investments. Included in investing activities is a cash flow of $75 million related to the long-term receivable from NEPC associated with the assumption of power purchase agreements. These cash flows offset cash payments made to NEPC which are reflected in operating activities.

Financing Activities

Results from PG&E NEG's consolidated cash flows from financing activities for the years ended December 31, 2002, 2001, and 2000 are as follows:

(in millions)

	2002	2001	2000

(in millions)	2002	2001	2000
Net borrowings (repayments) under credit facilities	$	$ (189)	$ (5)
Repayment of obligations due related parties and affiliates	(100)		
Advances from PG&E Corporation			79
Long-term debt issued	1,506	1,114	711
Long-term debt matured, redeemed, or repurchased	(403)	(757)	(85)
Notes issuance, net of discount and issuance costs		987	
Deferred financing costs	(41)	(39)	
Capital contributions			608
Distributions			(106)
Net cash provided by financing activities	$ 962	$ 1,116	$ 1,202

During 2002, PG&E NEG provided net cash flows from financing activities of $962 million.

PG&E NEG's cash inflows from financing activities were primarily attributable to increases in long-term debt issued relating to the continuing completion of PG&E NEG's construction facilities and borrowings under construction financing.

During 2001, net cash provided by financing activities was $1.1 billion, principally from the net proceeds related to the issuance of the Senior Unsecured Notes due 2011.

During 2000, net cash provided by financing activities was $1.2 billion. Net cash provided by financing activities resulted primarily from non-recourse project debt of $711 million, and capital contributions by PG&E Corporation of $608 million, partially offset by distributions to PG&E Corporation of $106 million.

PG&E Corporation

The following section discusses PG&E Corporation's significant cash flows from operating, investing, and financing activities for the years ended December 31, 2002, 2001, and 2000.

Operating Activities

Results from PG&E Corporation's consolidated cash flows from operating activities for the years ended December 31, 2002, 2001, and 2000 are as follows:

(in millions)	Year ended December 31,		
	2002	2001	2000
Net income (loss)	$ (874)	$ 1,099	$ (3,364)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,309	1,002	3,595
Net effect of changes in operating assets and liabilities:			
Restricted cash	(513)	(66)	(6)
Accounts receivable	51	1,000	(1,941)
Accounts payable	377	1,213	4,200
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	(1,442)	(16)	

(in millions)	Year ended December 31,		
Assets and liabilities of operations held for sale	34	(117)	64
Other, net	1,592	1,166	(1,793)
Net cash provided by operating activities	$ 534	$ 5,281	$ 755

Net cash provided by operating activities was $534 million in 2002, $5,281 million in 2001, and $755 million in 2000.

The decrease during 2002 was primarily due to the following factors:

The continued operation of the Utility as a debtor-in-possession under the Bankruptcy Code and the prior year impact of an income tax refund.

Increased working capital requirements of PG&E NEG, primarily due to increased credit collateral deposit requirements in PG&E NEG's trading operations.

The increase during 2001 was primarily due to the Utility's pre-petition obligations being stayed under the Bankruptcy Code, and deliveries on previously held trading positions at PG&E NEG.

Investing Activities

Results from PG&E Corporation's consolidated cash flows from investing activities for the year ended 2002, 2001, and 2000 are as follows:

(in millions)	Year ended December 31,		
	2002	**2001**	**2000**
Capital expenditures	$ (3,032)	$ (2,773)	$ (2,334)
Other, net	482	(103)	656
Net cash used by investing activities	$ (2,550)	$ (2,876)	$ (1,678)

Net cash used in investing activities in 2002, 2001, and 2000 was primarily for capital expenditures at the Utility and construction and development projects at PG&E NEG.

The decrease in cash used in investing activities in 2002, compared to 2001, was primarily due to the proceeds received by PG&E NEG from Attala Generating.

Financing Activities

Results from PG&E Corporation's consolidated cash flows from financing activities for the year ended 2002, 2001, and 2000 are as follows:

(in millions)	Year ended December 31,		
	2002	**2001**	**2000**

(in millions)	Year ended December 31,		
Net borrowings (repayments) under credit facilities	$	$ (1,148)	$ 2,846
Long-term debt issued	2,414	3,008	1,659
Long-term debt matured, redeemed, or repurchased	(1,644)	(868)	(865)
Rate reduction bonds matured	(290)	(290)	(290)
Common stock issued	217	15	65
Dividends paid		(109)	(436)
Other, net	(141)	(41)	21
Net cash provided by financing activities	$ 556	$ 567	$ 3,000

Net cash generated through financing activities in 2002, 2001, and 2000 was principally achieved through long-term debt issuances and increased borrowings under new and existing credit facilities. The decrease in net cash provided by financing activities in 2002, compared to 2001, of $11 million, was a result of the Utility's repayment of long-term debt, partly offset by PG&E NEG's increased borrowings under new and existing credit facilities.

During 2002, PG&E Corporation negotiated new terms to amend the Original Credit Agreement, reducing the principal balance from $1 billion to $720 million which included $300 million in new long-term debt.

RESULTS OF OPERATIONS

In this section, PG&E Corporation discusses earnings and the factors affecting them for each operating segment. The table below details certain items from the accompanying Consolidated Statements of Operations by operating segment for the years ended December 31, 2002, 2001, and 2000.

		PG&E National Energy Group					
(in millions)	Utility	Total PG&E NEG	Integrated Energy & Marketing Activities	Interstate Pipeline Operations	PG&E NEG Eliminations	PG&E Corporation, Eliminations and Other [1]	Total
2002							
Operating revenues [2]	$ 10,514	$ 2,075	$ 1,855	$ 253	$ (33)	$ (94)	$ 12,495
Operating expenses	6,601	4,812	4,653	109	50	(50)	11,363
Operating income (loss)	$ 3,913	$ (2,737)	$ (2,798)	$ 144	$ (83)	$ (44)	1,132
Interest income							132
Interest expense							(1,454)
Other income (expense), net							90
Loss before income taxes							(100)
Income benefit							(43)
Loss from continuing operations							(57)
Net loss							$ (874)
2001 [3]							
Operating revenues [2]	$ 10,462	$ 1,920	$ 1,680	$ 246	$ (6)	$ (172)	$ 12,210

		PG&E National Energy Group					
Operating expenses	7,984	1,787	1,679	109	(1)	(152)	9,619
Operating income (loss)	$ 2,478	$ 133	$ 1	$ 137	$ (5)	$ (20)	2,591
Interest income							167
Interest expense							(1,209)
Other income (expense), net							(31)
Income before income taxes							1,518
Income taxes							535
Income from continuing operations							983
Net income							$ 1,099
2000 (3)							
Operating revenues (2)	$ 9,637	$ 3,127	$ 2,009	$ 1,112	$ 6	$ (196)	$ 12,568
Operating expenses	14,838	2,858	1,937	906	15	(199)	17,497
Operating income (loss)	$ (5,201)	$ 269	$ 72	$ 206	$ (9)	$ 3	(4,929)
Interest income							214
Interest expense							(788)
Other income (expense), net							(23)
Loss before income taxes							(5,526)
Income benefit							(2,103)
Loss from continuing operations							(3,423)
Net loss							$ (3,364)

(1) PG&E Corporation eliminates all inter-segment transactions in consolidation.

(2) Operating revenues and expenses reflect the adoption during 2002 of a new accounting policy implementing a change from gross to net method of reporting revenues and expenses on trading activities. Prior year amounts for trading activities have been reclassified to conform with the new net presentation.

(3) Prior periods amounts have been restated to reflect the reclassification of USGenNE, Mountain View, and ET Canada operating results to discontinued operations.

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PG&E Corporation Consolidated

Overall Results

PG&E Corporation's net loss for the year ended December 31, 2002, was $874 million, compared to net income of $1,099 million for the same period in 2001, and a net loss of $3,364 million for the same period in 2000.

The significant changes in pre-tax income for both years ended December 31, 2002 and 2001, when compared to prior year are summarized in the table below:

(in millions)

	2002	2001
PG&E Corporation		
Interest expense	(121)	(105)
Interest and other income	72	17
Utility		
Electric revenues	852	472
Natural gas revenues	(800)	353
Cost of electricity	1,292	3,967
Deferred electric procurement costs		(6,465)
Cost of natural gas	878	(407)
Operating and maintenance	(432)	302
Depreciation amortization and decommissioning	(297)	2,615
Provision for loss on generation-related regulatory assets and under-collected power costs		6,939
Reorganization fees and expenses	(58)	(97)
Interest and other income	(35)	(76)
Interest expense	(14)	(355)
PG&E NEG		
Revenues	155	(1,207)
Cost of revenues	(197)	1,217
Impairments, write-offs, and other charges	(2,767)	
Operating expenses	(61)	(146)
Cumulative effect of change in accounting principle	(70)	9
Discontinued operations	(1,244)	48

PG&E Corporation's results of operations continue to be impacted by the California energy crisis, the Utility's bankruptcy filing, and the current liquidity and financial downturn at PG&E NEG. The overall results of the Utility and PG&E NEG are discussed separately below. Please see the Liquidity and Financial Resources section above, and Notes 2 and 3 of the Notes to the Consolidated Financial Statements for more information.

The changes in performance for the years ended December 31, 2002 and 2001, are attributable to the following factors:

PG&E Corporation

Interest Expense

In the third quarter, PG&E Corporation wrote off unamortized loan fees and discounts of $83 million relating to the prepayments of a portion of outstanding debt and $70 million relating to ratings waiver extensions. In addition, PG&E Corporation wrote off $38 million of unamortized loan discounts representing the value of unvested PG&E NEG options associated with the note prepayment.

Other Income

The third quarter change in the market value of vested PG&E NEG warrants previously issued in connection with the PG&E Corporation March 1, 2001, Credit Agreement totaled $71 million.

Dividends

No dividends were declared in 2002 or 2001 in accordance with the Credit Agreement, which prohibits PG&E Corporation from declaring or paying dividends until the term loans have been repaid.

In March 2001, PG&E Corporation paid $109 million of defaulted fourth quarter 2000 dividends in conjunction with the refinancing of PG&E Corporation obligations.

Utility

Electric Revenues

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

(in millions)	Year ended December 31,		
	2002	2001	2000
Residential	$ 3,646	$ 3,396	$ 3,062
Commercial	4,588	4,105	3,110
Industrial	1,449	1,554	1,053
Agricultural	520	525	420
Total	10,203	9,580	7,645
Direct access credits	$ (285)	$ (461)	$ (1,055)
DWR pass-through revenue	(2,056)	(2,173)	
Miscellaneous	316	380	264
Total electric operating revenues	$ 8,178	$ 7,326	$ 6,854

Electric revenues in 2002 increased $852 million, or 11.6 percent, from 2001. This increase in electric revenues was primarily due to three factors:

The amount of CPUC-authorized surcharges increased $751 million in 2002 from 2001. This increase reflects the collection of a $0.035 per kilowatt-hour (kWh) surcharge, effective June 2001, for all of 2002, as compared to the collection of this surcharge for only seven months during the twelve-month period ended December 31, 2001.

Direct access credits in 2002 decreased $176 million from 2001. In accordance with CPUC regulations, the Utility provides an energy credit to direct access customers (those who buy their electricity from another energy service provider, or ESP). The Utility bills direct access customers based on fully bundled rates, which includes generation, distribution, transmission, and other components. However, each direct access customer receives an energy credit equal to the procurement component of the fully bundled rates, which includes (1) the Utility's estimated procurement and generation cost, and (2) the Utility's generation component of the frozen rate for electricity provided by the DWR.
The decrease in direct access credits was due to a decrease in the average direct access credit per kWh offset by an increase in the total electricity provided to direct access customers by ESPs. The average direct access credit per kWh was higher in 2001 because in the beginning of 2001 the Utility used the California Power Exchange (PX) price for wholesale electricity to calculate direct access credits. Subsequent to the closure of the PX in January 2001, direct access credits have been calculated based on the procurement component of the fully bundled rate, which has been significantly lower than the PX price. The average direct access credit decreased from $0.116 per kWh in 2001 to $0.038 per kWh in 2002. In 2002, ESPs supplied

approximately 7,433 gigawatt-hours (GWh) of electricity to direct access customers, compared to 3,982 GWh in 2001.

Revenue passed through to the DWR decreased by $117 million in 2002. The Utility passes revenue through to the DWR for electricity procured by the DWR to cover the Utility's net open position (the amount of electricity needed by retail electric customers that cannot be met by utility-owned generation or electricity under contract to the Utility). Since January 2001, the DWR has been responsible for procuring electricity required to cover the Utility's net open position. Revenues collected on behalf of the DWR and the related costs are not included in the Utility's Consolidated Statement of Operations because the Utility acts only as the DWR's billing and collection agent.

The decrease in DWR pass-through revenues in 2002 was primarily due to a decrease in the Utility's net open position, which was created by (1) an increase in electricity supplied by ESPs to direct access customers, and (2) an increase in the amount of electricity the Utility was able to purchase from QFs due to renegotiated payment terms through the Utility's bankruptcy proceeding. The decrease in the Utility's net open position in 2002 was partially offset by the accrual of an additional $369 million in pass-through revenues in 2002 due to changes proposed by the DWR to the methodology used to calculate DWR remittances (see Note 2 of the Notes to the Consolidated Financial Statements).

Electric revenues in 2001 increased $472 million, or 6.9 percent, from 2000 mainly due to the CPUC-authorized surcharges implemented in January and June 2001 and a decrease in direct access credits. The decrease in direct access credits was due to a decrease in total electricity provided to direct access customers by direct access ESPs. In 2001, energy service providers supplied approximately 3,982 GWh of electricity to direct access customers, compared to 9,662 GWh in 2000.

The increase in electric revenues in 2001 was offset by revenues of $2,173 million passed through to the DWR in 2001, with no such amount in 2000.

Cost of Electricity

The following table shows a breakdown of the Utility's cost of electricity:

(in millions)	**Year ended December 31,**		
	2002	**2001**	**2000**
Cost of purchased power	$ 1,980	$ 3,224	$ 6,642
Fuel used in own generation	97	102	99
Other adjustments to cost of electricity	(595)	(552)	
Total cost of electricity	$ 1,482	$ 2,774	$ 6,741
Average cost of purchased power per kWh	$ 0.081	$ 0.143	$ 0.152
Total purchased power (GWh)	24,552	22,592	43,762

The cost of electricity in 2002 decreased $1,292 million, or 46.6 percent, from 2001. The decrease was attributable to the following factors:

A decrease in the average cost of purchased power. The more favorable price reflected the significantly lower prices for electricity subsequent to the stabilization of the energy market in the second half of 2001. In addition, the average cost of electricity decreased because the Utility purchased more electricity from QFs, other generators, and irrigation districts, which provided electricity at a lower cost than the electricity the Utility purchased on the market in the beginning of 2001. In 2002, the DWR purchased all of the electricity needed to meet the Utility's net open position, whereas in 2001 the Utility purchased the electricity itself through the PX market through the first half of January. As previously discussed, the Utility serves as a collection agent for the DWR and therefore does not reflect the DWR's cost of electricity in its Consolidated Statement of Operations; and

A net $595 million reduction to the cost of electricity recorded in March 2002 as a result of FERC and CPUC decisions, which allowed the Utility to reverse previously accrued California Independent System Operator (ISO) charges and to true-up the amount of previously accrued pass-through revenues payable to the DWR (see Note 2 of the Notes to the Consolidated Financial Statements).

Offsetting the above impacts were amounts recorded during 2001 that reduced purchased power costs by $552 million for the market value of terminated bilateral contracts with no similar amounts in 2002.

The cost of electricity in 2001 decreased $3,967 million, or 58.8 percent, from 2000. This decrease was primarily due to the following two factors:

After the first half of January 2001, the Utility no longer purchased electricity through the PX market. Instead, the DWR purchased electricity on behalf of the Utility's customers to cover the Utility's net open position; and

A statewide energy conservation campaign led the Utility's customers to use approximately 3 percent less energy than in 2000.

In 2000, the Utility deferred $6.5 billion in under-collected electric procurement costs. At the end of 2000, the Utility could no longer conclude that its under-collected electric procurement costs and generation-related regulatory assets were probable of recovery and therefore charged $6.9 billion to expense for these costs. There were no similar events in 2001.

Natural Gas Revenues

Natural gas revenues are made up of bundled gas revenues and transportation only revenues.

The following table shows a breakdown of the Utility's natural gas revenue:

(in millions)

	Year ended December 31,		
	2002	**2001**	**2000**
Bundled gas revenues	$ 1,882	$ 3,107	$ 2,229
Transportation service only revenue	316	375	338
Other	138	(346)	216
Total Natural Gas Revenues	$ 2,336	$ 3,136	$ 2,783

In 2002, natural gas revenues decreased $800 million, or 25.5 percent, from 2001 primarily as a result of a lower average cost of natural gas, which was passed along to customers through lower rates. The average bundled price of natural gas sold during 2002 was $6.72 per thousand cubic feet (Mcf) as compared to $10.55 per Mcf in 2001.

The decrease in transportation service only revenue resulted primarily from a decrease in demand for gas transportation services by gas-fired electric generators in California.

Increases in other gas revenues were mainly due to a decrease in the deferral of natural gas revenue in 2002, which was attributed to the abnormally high price for natural gas in the beginning of 2001. The Utility tracks natural gas revenues and costs in natural gas balancing accounts. Over-collections and under-collections are deferred until they are refunded to or received from the Utility's customers through rate adjustments.

In 2001, natural gas revenues increased $353 million, or 12.7 percent, due to a higher average cost of natural gas, which was passed on to customers through higher rates. The average bundled price of natural gas sold during 2001 was $10.55 per Mcf, compared to $8.40 per Mcf in

2000. The increase was

offset by an approximate 4 percent decrease in usage in 2001 primarily as a result of conservation efforts.

The increase in transportation service only revenue was primarily due to an increase in demand for gas transportation services by gas-fired electric generators in California.

Decreases in other gas revenues were mainly due to an increase in the deferral of natural gas revenue in 2001, which was attributed to the abnormally high price for natural gas in 2001. As previously discussed, over-collections are deferred in natural gas balancing accounts until they are refunded to customers through rate adjustments.

Cost of Natural Gas

The following table shows a breakdown of the Utility's cost of natural gas:

(in millions)	Year ended December 31,		
	2002	2001	2000
Cost of natural gas purchased	$ 853	$ 1,593	$ 1,331
Cost of gas transportation	101	239	94
Total cost of natural gas	$ 954	$ 1,832	$ 1,425

In 2002, the Utility's cost of natural gas decreased $878 million, or 47.9 percent, from 2001 primarily due to a decrease in the average market price of natural gas purchased from $6.77 per Mcf in 2001 to $3.38 per Mcf in 2002.

Additionally, the Utility's cost to transport gas to its service area decreased significantly in 2002 due to $111 million in costs recognized in 2001 related to the involuntary termination of gas transportation hedges caused by a decline in the Utility's credit rating. There were no similar events in 2002.

In 2001, the Utility's cost of natural gas increased $407 million, or 28.6 percent, primarily due to an increase in the average cost of natural gas from $5.07 per Mcf in 2000 to $6.77 per Mcf in 2001. Furthermore, as mentioned above, in 2001 the Utility's cost to transport gas to its service area increased significantly due to $111 million in costs related to the involuntary termination of gas transportation hedges.

Other Operating Expenses

Operating and Maintenance

In 2002, the Utility's operating and maintenance expenses increased $432 million, or 18.1 percent, from 2001. This increase is mainly due to the following factors:

- Increases in employee benefit plan-related expenses primarily due to unfavorable returns on plan investments and lower interest rates, which caused a decrease in discount rates on the Utility's present- valued benefit obligations;
- Increases in environmental liability estimates;
- Increases in customer accounts and service expenses related to the Utility's new customer billing system;

The amortization of previously deferred electric transmission related costs, which are now being collected in rates; and

The deferral of over-collected electric revenue associated with the rate reduction bonds. Prior to 2000, these revenues were used to finance the rate reduction implemented in 1998.

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In 2001, the Utility's operating and maintenance expenses decreased $302 million, or 11.2 percent, primarily due to a reserve for chromium litigation of $140 million recorded in 2000, and lower regulatory and generation-related costs.

Depreciation, Amortization, and Decommissioning

Depreciation, amortization, and decommissioning expenses increased $297 million, or 33.1 percent, in 2002. This increase was due mainly to amortization of the rate reduction bond regulatory asset, which began in January 2002, and totaled $290 million through December 31, 2002. The rate reduction bond regulatory asset is discussed further in the "Regulatory Matters" section of this MD&A.

Depreciation, amortization, and decommissioning expenses decreased $2,615 million, or 74.5 percent, in 2001 due to accelerated depreciation of generation-related assets in 2000. Less depreciation was recorded in 2001 as the majority of the generation-related assets had been fully depreciated after the acceleration.

Interest Income

In accordance with the American Institute of Certified Public Accountants' Statement of Position (SOP) 90-7, the Utility reports reorganization interest income separately on the Consolidated Statements of Operations. Such income primarily includes interest earned on cash accumulated during the proceedings. Interest income decreased $49 million, or 39.8 percent, in 2002. The decrease in interest income in 2002 was due in most part to lower average interest rates on the Utility's short-term investments.

In 2001, the Utility's interest income decreased $63 million, or 33.9 percent, compared to 2000 due primarily to the write-off of generation-related regulatory balancing account interest. The decrease was offset by increases in interest on short-term investments and balancing accounts.

Interest Expense

In 2002, the Utility's interest expense increased $14 million, or 1.4 percent, from 2001 due to the Utility's bankruptcy proceeding, which has resulted in higher negotiated interest rates and an increased level of unpaid debts accruing interest. See the discussion of interest rates in Note 2 of the Notes to the Consolidated Financial Statements.

In 2001, the Utility's interest expense increased $355 million, or 57.3 percent, compared to 2000 due to increased debt levels and higher interest rates as a result of the Utility's credit rating downgrade and subsequent bankruptcy.

Reorganization Fees and Expenses

In accordance with SOP 90-7, the Utility reports reorganization fees and expenses separately on the Consolidated Statements of Operations. Such costs primarily include professional fees for services in connection with Chapter 11 proceedings and totaled $155 million in 2002 and $97 million in 2001.

PG&E NEG

Overall Results

The year ended 2002 included an expected loss on the disposal of USGenNE of $1.1 billion and on ET Canada of $25 million. Additionally, the earnings from operations of USGenNE, ET Canada, and Mountain View were reclassified to discontinued operations. USGenNE, ET Canada, and Mountain View Power Partners, LLC and Mountain View Power Partners II, LLC (collectively referred to as Mountain View) were determined to be Assets Held for Sale per SFAS No. 144. As such, their operating results were reclassified to discontinued operations and an evaluation of the value on an asset-by-asset basis conducted. PG&E NEG determined that USGenNE's and ET Canada's book values exceeded their anticipated selling prices and as such recorded losses on disposal. Earnings from operations included in discontinued operations were $11 million or a decrease of $96 million principally due to USGenNE's unfavorable operating results and market conditions in New England.

The year ended 2002 included a net loss for the cumulative effect of a change in accounting principle of $61 million. The cumulative effect was based on PG&E NEG's adoption as of April 1, 2002, of interpretations issued by the Derivatives Implementation Group (DIG), DIG C15 and DIG C16, reflecting the mark-to-market value of certain contracts that had previously been accounted for under the accrual basis as normal purchases and sales.

PG&E NEG's income from continuing operations (after-tax) was a loss of $2.2 billion in 2002 or a decrease of $2.3 billion from the prior year. The decline in pre-tax operating income was mainly due to one-time impairments, write-offs and other charges previously discussed and taken during 2002 of $2.8 billion.

PG&E NEG's net income (after discontinued operations and cumulative effect of a change in accounting principle) was $171 million for the year ended 2001, an increase of $19 million from the year ended 2000.

The year ended 2001 included earnings from discontinued operations related to USGenNE, Mountain View, and ET Canada of $107 million, or an increase of $8 million from 2000. In addition, the year ended 2000 included a loss from discontinued operations of $40 million related to losses on the disposal of PG&E Energy Services Corporation.

The year ended 2001 included a net gain for the cumulative effect of a change in accounting principle of $9 million. The cumulative effect was based on an interpretation issued by the DIG C11 that clarified how certain commodity contracts should be treated. In applying this new DIG guidance, PG&E NEG determined that one of its derivative contracts no longer qualified for normal purchases and sales treatment and must be marked-to-market through earnings.

PG&E NEG's income from continuing operations (after-tax) was $55 million in 2001 or a decrease of $38 million from the prior year. The decline in pre-tax operating income of $97 million in 2001 was primarily due to the sale of Pacific Gas Transmission Teco, Inc., and subsidiaries (collectively referred to as PG&E GTT) in December 2000 which provided operating income of $77 million in 2000, and a charge in the fourth quarter of 2000 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 Activities (Energy) segment. Net interest expense was $33 million lower in 2001 as compared to the prior year, principally due to increased capitalization of interest for projects under construction.

Operating Revenues

PG&E NEG's operating revenues were $2.1 billion for the year ended 2002, an increase of $155 million from the year ended 2001. These revenue increases occurred primarily in PG&E NEG's Energy segment principally due to new generation plants coming on line within the wholesale energy business. The principal drivers in the increase in PG&E NEG's Interstate Pipeline Operation (Pipeline) segment's operating revenues, which increased $7 million, were due to the North Baja pipeline commencing operations and PG&E GTN contract termination settlements. These operating revenue increases in the Pipeline segment were slightly offset by weak pricing fundamentals on gas transportation to the California and Pacific Northwest gas markets compared to the same period last year.

PG&E NEG's operating revenues were $1.9 billion in 2001, a decrease of $1.2 billion or 39 percent from 2000. This decline in operating revenues occurred within both PG&E NEG's Energy and Pipeline segments. The decline in PG&E NEG's Energy segment of $329 million is mainly due to lower trade volumes and lower realized prices in the third and fourth quarter 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. The decline in PG&E NEG's Pipeline segment of $866 million is primarily due to the sale of PG&E GTT in December 2000.

Operating Expenses

PG&E NEG's operating expenses were $4.8 billion for the year ended 2002, an increase of $3 billion from the same period in the prior year. These increases occurred primarily in PG&E NEG's Energy segment, principally due to impairments, write-offs, and other charges previously discussed of $2.8 billion. The cost of commodity sales and fuel increased $197 million in line with the increases in operating revenues, compressed spark spreads, and new generation plants coming on line within the wholesale energy business. Operations, maintenance and management costs increased $33 million in 2002 as compared to the same period last year primarily due to new plants coming on line. In addition, depreciation and amortization costs increased $15 million in the period also mainly due to new plants coming on line. Administrative and general costs increased in 2002 as compared to the same period last year due to charges associated with PG&E NEG's cost reduction and restructuring programs. These increases were slightly offset on a year-to-date basis by lower costs in the first half of 2002 associated with lower employee related expense.

PG&E NEG's operating expenses were $1.8 billion in 2001, a decrease of $1.1 billion from 2000. This decline in operating expenses occurred within both PG&E NEG's Energy and Pipeline segments. The decline in PG&E NEG's Energy segment of $258 million 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. The decline in PG&E NEG's Pipeline segment of $792 million is primarily due to the sale of PG&E GTT in December 2000.

INFLATION

PG&E Corporation and the Utility prepare financial statements in accordance with accounting principles generally accepted in the United States of America. This means PG&E Corporation and the Utility report operating results in terms of historical costs and do not evaluate the impact of inflation.

Inflation affects 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, PG&E Corporation and the Utility do not expect current inflation levels to have a material adverse impact on PG&E Corporation's or the Utility's financial position or results of operations.

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.

Utility

The Utility is the only subsidiary with significant regulatory proceedings or issues at this time. These are discussed below. Regulatory proceedings associated with electric industry restructuring are further discussed in Note 2 of the Notes to the Consolidated Financial Statements.

DWR Revenue Requirement and Servicing Order

In January 2001, the DWR began purchasing electricity on behalf of the Utility's customers in accordance with a new state law, Assembly Bill (AB) 1X, that authorized the DWR to purchase electricity for California utility customers to the extent that it could not be supplied or purchased by the utilities (the amount of electricity needed to meet customers' demand that cannot be provided by the IOUs, either through their own generation or by suppliers under contracts with the IOUs, is referred to as the net open position). The DWR initially purchased electricity on the spot market until it was able to enter into long-term contracts for the supply of electricity. Under AB 1X, the DWR was prohibited from entering into new agreements to purchase electricity to meet the net open position of the California IOUs after December 31, 2002.

The DWR pays for its costs of purchasing electricity from a revenue requirement charged to Utility ratepayers (power charge) and proceeds of the DWR's $11.3 billion bond financing completed in November 2002 (see "DWR Bond Charge" below).

In February 2002, the CPUC approved a decision that set the statewide DWR revenue requirement for 2001 and 2002. In March 2002, the CPUC reallocated the amounts contained in the February 2002 decision among the customers of the three California IOUs. The March 2002 decision allocated $4.4 billion of a total statewide power charge revenue requirement of approximately $9.0 billion to the Utility's customers. Of the $4.4 billion allocated to the customers of the Utility, approximately $1.8 billion related to 2002 power charges and approximately $2.6 billion related to 2001 power charges.

In May 2002, the CPUC approved a servicing order between the Utility and the DWR, which sets forth the terms and conditions under which the Utility provides the transmission and distribution of the DWR-purchased electricity; addresses billing, collection and related services on behalf of the DWR; and addresses the DWR's compensation to the Utility for providing these services. In October 2002, the DWR filed a proposed amendment to the CPUC's May 2002 servicing order. The DWR's proposed amendment changes the calculation that determines the amount of revenues that the Utility must pass-through to the DWR. This proposed amendment would also be used to true-up previous amounts passed through to the DWR as well as future payments. Under its statutory authority, the DWR may request the CPUC to order the utilities to implement such amendments, and the CPUC has approved such amendments in the past without significant change. In December 2002, the CPUC approved an operating order requiring the Utility to perform the operational, dispatch, and administrative functions for the DWR's allocated contracts beginning on January 1, 2003. (See "CPUC Operating Order" below.) The operating order, which applies prospectively, includes the DWR's proposed method of calculating the amount of revenues that the Utility must pass-through to the DWR. As a result, as of December 31, 2002, the Utility has accrued an additional $369 million (pre-tax) liability for pass-through revenues for electricity provided by the DWR to the Utility's customers in 2002 and 2001. A separate proceeding will consider a revision or true-up for the revenue requirements remitted to the DWR for 2002 and 2001 costs, once final 2002 cost data is available. This true-up proceeding is scheduled for April 2003.

In December 2002, the CPUC issued a decision allocating approximately $2 billion of the DWR's 2003 power charge-related revenue requirement to the Utility's customers. This revenue requirement includes the costs associated with the DWR contracts allocated to the Utility's customers by the CPUC in September 2002. The DWR plans to submit a revised 2003 power charge-related revenue requirement to the CPUC in late March 2003.

Before the DWR's 2003 statewide revenue requirement filing with the CPUC in August 2002, the Utility filed comments with the DWR alleging that major portions of the DWR's revenue requirements were not "just and reasonable" as required by AB 1X and that the DWR was not complying with the procedural requirements of AB 1X in making its determination. On August 26, 2002, the Utility filed with the DWR a motion for reconsideration of the DWR's determination that its revenue requirements

were "just and reasonable." The DWR denied the Utility's motion on October 8, 2002. On October 17, 2002, the Utility filed a lawsuit in a California court asking the court to find that the DWR's revenue requirements had not been demonstrated to be "just and reasonable" and lawful, and that the DWR had violated the procedural requirements of AB 1X in making its determination. In part, the Utility based its allegations on the State of California's petition pending before the FERC seeking to set aside many of the DWR contracts on the basis that they are not "just and reasonable." The Utility asked that the court order the DWR's revenue requirement determination be withdrawn as invalid, and that the DWR be precluded from imposing its revenue requirements on the Utility and its customers until it has complied with the law. No schedule has yet been set for consideration of the lawsuit.

Until the CPUC modifies the curent frozen rate structure, changes to the DWR's 2003 revenue requirement may affect the Utility's future earnings. Because the Utility acts as a collection agent for the DWR, amounts collected on behalf of the DWR (related to its revenue requirement) are excluded from the Utility's revenues.

DWR Bond Charge

On October 24, 2002, the CPUC issued a decision that, in part, imposes bond charges to recover the DWR's bond costs from most bundled customers starting November 15, 2002, although the decision found that the Utility would not need to increase customer's overall rates to incorporate the bond charge. The DWR bond charge also will be imposed on all direct access customers, as described below.

On December 30, 2002, the CPUC revised the 2003 bond charge to $0.005 per kWh, effective January 6, 2003. The Utility expects to accrue bond-related charges of approximately $340 million during the 12 months ending November 14, 2003.

Until the CPUC implements bottoms-up billing (billing for specific rate components) for the Utility, any bond charges will reduce the amount of revenue available to recover previously written-off under-collected purchased power costs and transition costs.

Senate Bill 1976

Under AB 1X, the DWR is prohibited from entering into new agreements to purchase electricity to meet the net open position of the California IOUs after December 31, 2002. In September 2002, the Governor signed California SB 1976 into law. SB 1976 required that each

California IOU submit, within 60 days after the CPUC allocated existing DWR contracts for electricity procurement to the customers of each California IOU, an electricity procurement plan to meet the residual net open position associated with that utility's customer demand. SB 1976 requires that each procurement plan include one or more of the following features:

- A competitive procurement process under a format authorized by the CPUC, with the costs of procurement obtained in compliance with the authorized bidding format being recoverable in rates;
- A clear, achievable, and quantifiable incentive mechanism that establishes benchmarks for procurement and authorizes the IOUs to procure electricity from the market subject to comparison with the CPUC-authorized benchmarks; or
- Upfront and achievable standards and criteria to determine the acceptability and eligibility for rate recovery of a proposed transaction and an expedited CPUC pre-approval process for proposed bilateral contracts to ensure compliance with the individual utility's procurement plan.

SB 1976 provides that the CPUC may not approve the procurement plan if it finds the plan contains features or mechanisms, which would impair restoration of the IOU's creditworthiness or would lead to a deterioration of the IOU's creditworthiness. SB 1976 also indicates that procurement activities in compliance with an approved procurement plan will not be subject to after-the-fact

reasonableness review. The CPUC is permitted to establish a regulatory process to verify and ensure that each contract was administered in accordance with its terms and that contract disputes are resolved reasonably.

A central feature of the SB 1976 regulatory framework is its direction to the CPUC to create new electric procurement balancing accounts to track and allow recovery of the differences between recorded revenues and costs incurred under an approved procurement plan. The CPUC must review the revenues and costs associated with the IOU's electric procurement plan at least semi-annually and adjust rates or order refunds, as appropriate, to properly amortize the balancing accounts. Until January 1, 2006, the CPUC must establish the schedule for amortizing the over-collections or under-collections in the electric procurement balancing accounts so that the aggregate over-collections or under-collections reflected in the accounts do not exceed 5 percent of the IOU's actual recorded generation revenues for the prior calendar year, excluding revenues collected on behalf of the DWR. Mandatory semi-annual review and adjustment of the balancing accounts will continue until January 1, 2006, after which time the CPUC is required to conduct electric procurement balancing account reviews and adjust retail ratemaking amortization schedules for the balancing accounts as the CPUC deems appropriate and in a manner consistent with the requirements of SB 1976 for timely recovery of electric procurement costs.

On January 1, 2003, the California IOUs resumed the function of procuring electricity to meet that portion of their customers' needs that is not covered by the combination of the allocation of electricity from existing DWR contracts and the IOU's own electric resources and contracts.

Allocation of DWR Electricity to Customers of the IOUs

Consistent with applicable law and CPUC orders, since 2001, the Utility and the other California IOUs have acted as the billing and collection agents for the DWR's sales of its electricity to retail customers. In September 2002, the CPUC issued a decision to allocate the electricity provided under existing DWR contracts to the customers of the IOUs. This decision required the Utility, along with the other IOUs, to begin performing all the day-to-day scheduling, dispatch, and administrative functions associated with the DWR contracts allocated to the IOUs' portfolios on January 1, 2003. The DWR retains legal and financial responsibility for these contracts.

Under AB 1X, the CPUC has no review authority over the reasonableness of procurement costs in the DWR's contracts, although the Utility's administration of DWR contracts allocated to its customers and its dispatch of the electricity associated with those contracts may be subject to reasonableness reviews. Under a December 2002 interim opinion, the CPUC established a maximum annual procurement disallowance equal to twice the Utility's annual administrative costs of managing procurement activities, including the administration and dispatch of electricity associated with DWR allocated contracts. The Utility anticipates that its annual administrative cost of managing procurement activities in 2003 will be approximately $18 million.

The DWR has stated publicly that it intends to transfer full legal title of, and responsibility for, the DWR electricity contracts to the IOUs as soon as possible. However, SB 1976 does not contemplate a transfer of title of the DWR contracts to the IOUs. In addition, the operating order issued by the CPUC in December 2002 implementing the Utility's operational and scheduling responsibility with respect to the DWR allocated contracts specifies that the DWR will retain legal and financial responsibility for the contracts and that the December 2002 order does not result in an assignment of the DWR allocated contracts to the Utility. However, there can be no assurance that either the State of California or the CPUC will not provide the DWR with authority to affect such a transfer of legal title in the future. The Utility has informed the CPUC, the DWR, and the State of California that the Utility would vigorously oppose any attempt to transfer the DWR allocated contracts to the Utility without its consent.

CPUC Operating Order

In December 2002, the CPUC adopted an operating order requiring the Utility to perform the operational, dispatch, and administrative functions for the DWR's allocated contracts beginning on January 1, 2003. (Similar operating orders were also adopted for the other two California IOUs.) The operating order sets forth the terms and conditions under which the Utility will administer the DWR allocated contracts and requires the Utility to dispatch all of the generating assets within its portfolio on a least-cost basis for the benefit of the Utility's customers. The order specifies that the DWR will retain legal and financial responsibility for the DWR allocated contracts and that the order does not result in an assignment of the allocated DWR contracts to the Utility.

Operating Agreement

The CPUC had previously ordered the IOUs to work with the DWR to submit to the CPUC proposed operating agreements governing the DWR allocated contracts. When the operating orders were issued, the DWR and the IOUs had not yet finalized their separate operating agreements. In its decision issuing the operating orders, the CPUC noted that if the IOUs and the DWR eventually reach mutual agreement, the CPUC would consider modifying its decision on an expedited basis to terminate the operating orders and approve the operating agreements, assuming that the operating agreements adopted a framework that was substantially similar to the one imposed by the operating orders.

On December 20, 2002, the Utility and the DWR executed an operating agreement following several months of negotiation. The agreement provides that it will not become effective unless approved by the CPUC. The Utility has submitted the agreement to the CPUC for approval and has requested that the CPUC terminate the operating order and approve the operating agreement.

Although the operating order and the operating agreement have fundamentally the same objectives, the operating agreement, among other things:

- Provides an adequate contractual basis for establishing a limited agency relationship between the Utility and the DWR;
- Limits the Utility's contractual liability to the DWR and other parties to $5 million per year plus 10 percent of damages in excess of $5 million with a limit of $50 million over the term of the agreement; and
- Clarifies that the DWR does not intend to, nor is it the DWR's responsibility to, review the Utility's least-cost dispatch performance, other than to verify compliance with the supplier contracts.

On December 30, 2002, the Utility filed an application for rehearing of the operating order decision with the CPUC. On January 1, 2003, after having reserved all rights associated with challenges to the operating order, the Utility commenced providing contract administration, scheduling and dispatch services to the DWR under the CPUC's operating order.

Approval of Procurement Plan

In October 2002, the CPUC issued a decision ordering the Utility to resume full procurement on January 1, 2003. In December 2002, the CPUC issued an interim opinion adopting the revised electricity procurement plan for 2003 that the Utility submitted in 2002 and authorized the Utility to enter into contracts designed to hedge its residual net open position for the first quarter of 2004. The CPUC found that the maximum annual procurement disallowance exposure that each IOU should face for all of its procurement activities should be limited to twice the IOU's annual administrative costs of managing procurement activities, including its administration and dispatch of electricity associated with DWR contracts allocated to its customers. The Utility anticipates that its annual administrative costs of managing procurement activities in 2003 will be approximately $18 million. While the Utility's procurement plan covered procurement activities only for the 2003 calendar year, the CPUC authorized the IOUs to extend their planning into the first quarter of 2004.

Effective January 1, 2003, the Utility established the Energy Resource Recovery Account (ERRA) to record and recover electricity costs, excluding the DWR's electricity contract costs, associated with the Utility's authorized procurement plan. Electricity costs recorded in the ERRA include, but are not limited to, fuel costs for retained generation, QF contracts, inter-utility contracts, ISO charges, irrigation district contracts, other power purchase agreements, bilateral contracts, forward hedges, pre-payments, collateral requirements associated with procurement (including disposition of surplus electricity), and ancillary services. The Utility offsets these costs by reliability-must-run revenues, the Utility's allocation of surplus sales revenues and the ERRA revenue requirement. The CPUC has approved, on a preliminary basis, a starting ERRA revenue requirement of $2.0 billion for the Utility.

The CPUC has authorized the Utility to file an application to change retail electricity rates at any time that its forecasts indicate it will face an under-collection of electricity procurement costs in excess of 5 percent of its prior year's generation and procurement revenues, excluding amounts collected for the DWR. The Utility currently estimates that its 5 percent threshold amount will be approximately $224 million.

In February 2003, the Utility filed its 2003 ERRA forecast application requesting that the CPUC reset the Utility's 2003 ERRA revenue requirement to $1.4 billion and that the ERRA trigger threshold of $224 million be adopted. The CPUC will examine the Utility's forecast of costs for 2003 and will finalize the Utility's starting ERRA revenue requirement and ERRA trigger threshold when it reviews the Utility's ERRA application.

The Utility intends to submit its long-term procurement plan, covering the next 20 years by April 1, 2003, and the CPUC has stated that it plans to issue a final decision on the Utility's long-term procurement plan in November 2003.

In April 2001, the California Public Utilities Code was amended to require that the CPUC ensure that errors in estimates of demand elasticity or sales by the Utility do not result in material over- or under-collections of costs by the Utility. The Utility intends to address implementation of this new law in connection with pending proceedings at the CPUC relating to recovery of components of its costs of service.

2001 Annual Transition Cost Proceeding: Review of Reasonableness of Electricity Procurement

On January 11, 2002, as directed by the CPUC, the Utility filed a report with the CPUC detailing the reasonableness of the Utility's electric procurement and generation scheduling and dispatch activities for the period July 1, 2000, through June 30, 2001. In this proceeding, the CPUC will review the reasonableness of the Utility's procurement of wholesale electricity from the PX and ISO during the height of the 2000 - 2001 California energy crisis. With the exception of a limited right to purchase electricity from third parties beginning in August 2000, all of the Utility's wholesale electric purchases during this period were required to be made exclusively from or through the PX and ISO markets pursuant to FERC-approved tariffs. Prior CPUC decisions have determined that such purchases should be deemed reasonable. In addition, the Utility's complaint against the CPUC Commissioners asserts that the costs of such purchases are recoverable in the Utility's retail rates without further review by the CPUC under the federal filed rate doctrine. However, a CPUC administrative law judge is asserting jurisdiction to review the reasonableness of the Utility's wholesale electric purchases from the PX and ISO in the proceeding. A report from the CPUC's Office of Ratepayer Advocates (ORA) regarding the Utility's procurement activities for the covered period is due April 28, 2003. It is possible this review could result in disallowance of certain costs associated with the Utility's purchases from the PX and ISO during the 2000 - 2001 period.

Retained Generation Revenue Requirement

The CPUC has approved a 2002 revenue requirement of $3 billion for recovery of costs of generation the Utility retains, including electric purchase expenses, depreciation, operating expenses, taxes, and return on investment, based on the net regulatory value as of December 31, 2000.

The CPUC has allowed the Utility to recover reasonable costs incurred in 2002 for its own electric generation, subject to reasonableness review in the Utility's 2003 General Rate Case (GRC) proceeding. The decision does not change retail electric rates and the Utility does not expect it to have an impact on the Utility's results of operations. Instead, the decision defers consideration of future rate changes until the CPUC addresses the status of the retail rate freeze. The CPUC also deferred addressing recovery of the Utility's past unrecovered generation-related costs.

The CPUC is considering the Utility's 2003 retained generation revenue requirement as part of the Utility's 2003 GRC proceeding. The Utility's 2003 GRC application requested an increase in non-fuel generation revenue requirements of $149 million over the amount authorized for 2002. This requested revenue requirement increases the Utility's estimated fuel and procurement costs recorded in the ERRA (see "Approval of Procurement Plan" above), and the DWR's power charges.

Divestiture of Retained Generation Facilities

The California Legislature passed AB 6X in January 2001 prohibiting utilities from divesting their remaining power plants before January 1, 2006. The Utility believes this law does not supersede or repeal existing provisions of AB 1890, California's 1996 electric industry restructuring legislation, requiring the CPUC to establish a market value for the Utility's remaining generating assets by the end of 2001, based on appraisal, sale or other divestiture. The Utility has filed comments on this matter with the CPUC. However, the CPUC has not yet issued a decision.

On January 2, 2002, the CPUC issued a decision finding that AB 6X had materially affected the implementation of AB 1890. The CPUC scheduled further proceedings to address the impact of AB 6X on the AB 1890 rate freeze for the Utility and to determine the extent and disposition of the Utility's remaining unrecovered transition costs. In its November 2002 decision regarding surcharge revenues (see "One-Cent, Three-Cent, and Half-Cent Surcharge Revenues" below), the CPUC reiterated that it had yet to decide when the rate freeze ended and the disposition of any under-collected costs remaining at the end of the rate freeze.

On January 17, 2002, the Utility filed an administrative claim with the State of California Victim Compensation and Government Claims Board, or Claims Board, alleging that AB 6X violates the Utility's statutory rights under AB 1890. The Utility's claim seeks compensation for the denial of its right to at least a $4.1 billion market value of its retained generating facilities. On March 7, 2002, the Claims Board formally denied the Utility's claim. Having exhausted remedies before the Claims Board, on September 6, 2002, the Utility filed a complaint against the State of California for breach of contract in the California Superior Court. On January 9, 2003, the Superior Court granted the State's request to dismiss the Utility's complaint, finding that AB 1890 did not constitute a contract. The Utility has 60 days to file an appeal and intends to do so.

Direct Access Suspension and Cost Responsibility Surcharge

Until September 2001, California utility customers could choose to buy their electricity from the Utility (bundled customers) or from an alternative power supplier through "direct access" service. Direct access customers receive distribution and transmission service from the Utility, but purchase electricity (generation) from their alternative provider. In September 2001, the CPUC, pursuant to AB 1X, suspended the right of retail end-use customers to choose direct access service, thereby preventing additional customers from entering into contracts to purchase electricity from alternative providers. Customers that entered into direct access contracts on or before September 20, 2001, were permitted to remain on direct access.

In November 2002, the CPUC issued a decision assessing an exit fee, or non-bypassable charge, on direct access customers to avoid a shift of costs from direct access customers to bundled service customers.

The decision establishes the Cost Responsibility Surcharge (CRS) and imposes a cap of $0.027 per kWh. The CPUC required the utilities to implement this surcharge on January 1, 2003. The CPUC has

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indicated that it will establish an expedited review schedule to determine whether the cap should be adjusted. The CPUC also has indicated that it will reach a decision on whether this cap should be adjusted, and whether trigger mechanisms for adjusting the cap should be established, by July 1, 2003. The Utility implemented the $0.027 per kWh CRS on January 1, 2003. (See "Direct Access Credits" below.)

Funds remitted under the CRS will be applied first to the DWR, then to the Utility's ongoing procurement and generation costs. Direct access customers who have returned to bundled service will be responsible for their share of the unrecovered costs resulting from the CRS. To the extent the cap results in an under-collection of DWR charges, the shortfall would have to be remitted to the DWR from bundled customers' funds. On an interim basis while the CPUC examines a long-term plan for financing the CRS, interest on under-collections will be assessed at the interest rate paid by the DWR on bonds issued to finance electricity purchases.

The Utility does not expect that the CPUC's implementation of this decision or the level of the CRS cap will have a material adverse effect on its results of operations or financial condition.

Direct Access Credits

When the direct access credit was established, direct access customers paid the full bundled rate less a credit based on the Schedule PX price. Under this methodology, when the Schedule PX price exceeded the bundled rates, the direct access customer received a bill credit. As a result, during the energy crisis, direct access customers did not contribute to the Utility's transition cost recovery nor did they pay for transmission and distribution services. Under the interim direct access credit methodology in place since the PX ceased operations in January 2001, the Utility has calculated the Schedule PX price using an estimate of its cost of service for its retained generation and the Utility's generation component of the frozen rate for energy provided by the DWR. Beginning January 1, 2003, the Utility reduced this direct access credit by the additional direct access exit fee of up to the $0.027 per kWh CRS cap.

Additionally, direct access customers paid the one-cent surcharge in 2001 and 2002, but were exempt from the three-cent surcharge and half-cent surcharge. In May 2001, the Utility also requested authorization to charge direct access customers for the three-cent surcharge. One party filed a protest indicating that direct access customers should not pay the three-cent surcharge, nor the one-cent surcharge beginning June 1, 2001. The one-cent surcharge generates approximately $80 million in revenues per year from direct access customers. The CPUC has not yet ruled on this issue. It is unclear how or whether direct access customers would be reimbursed if the CPUC rules that direct access customers should not have paid this charge. In November 2002, the CPUC determined that direct access customers should pay a portion of DWR's costs beginning in 2003 to keep bundled customers indifferent as to the level of direct access. As a result, on January 1, 2003, direct access customers began paying a $0.027 per kWh surcharge, and they no longer pay the $0.01 per kWh surcharge.

On May 31, 2002, the Utility filed its proposal for calculating the post-PX direct access credit that would continue allowing direct access customers to receive a credit for generation-related costs avoided as a result of their self-procurement. Specifically, the Utility proposed that the credit be based on avoided procurement costs. The Utility also proposed to move to bottoms-up billing (billing for specific rate components rather than a frozen rate) for direct access customers as quickly as possible. Under bottoms-up billing, direct access customers' rates would be calculated based on the services they actually take from the Utility, such as transmission and distribution, the fixed transition amount related to the rate reduction bond repayment (if applicable), and any non-bypassable charges that the CPUC approves including nuclear decommissioning and public purpose programs, as well as the direct access Customer Responsibility Surcharge described above. Consequently, direct access customers would pay at least the same non-procurement charges that are applicable to bundled customers.

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The Utility proposed to adjust the direct access credit retroactively to December 28, 2000, using the Dow Jones Index after January 18, 2001, and to limit the amount of the credit to the price cap established by the FERC.

One-Cent, Three-Cent, and Half-Cent Surcharge Revenues

In the first quarter of 2001, the CPUC authorized the Utility to begin collecting energy purchase surcharge revenues totaling $0.04 per kWh (composed of a $0.01 per kWh surcharge revenue approved in January and a $0.03 per kWh surcharge revenue approved in March). The CPUC ordered the Utility to apply these new rates only to "ongoing procurement costs" and "future power purchases."

Although the CPUC authorized the $0.03 per kWh surcharge in March 2001, the Utility did not begin collecting the revenues until June 2001. As a result, in May 2001, the CPUC authorized the Utility to collect an additional $0.005 per kWh surcharge revenue for 12 months to make up for the time lag in collection of the $0.03 per kWh surcharge revenues. Although the collection of this "half-cent surcharge" was originally scheduled to end on May 31, 2002, the CPUC issued a resolution ordering the Utility to continue collecting the half-cent surcharge until further consideration by the CPUC. The Utility had recorded a regulatory liability for these $0.01 per kWh and $0.03 per kWh surcharge revenues when such surcharges exceeded ongoing procurement costs and a regulatory liability for the $0.005 per kWh surcharge revenues billed subsequent to May 31, 2002. These regulatory liabilities totaled $222 million as of September 30, 2002, and $65 million as of December 31, 2001.

In November 2002, the CPUC approved a decision modifying the restrictions on the use of revenues generated by the surcharges to permit the revenues to be used for the purpose of securing or restoring the Utility's reasonable financial health, as determined by the CPUC. The CPUC will determine in other proceedings how the surcharge revenues can be used, whether there is any cost or other basis to support specific surcharge levels, and whether the resulting rates are just and reasonable. After the CPUC determines when the AB 1890 rate freeze ended, the CPUC will determine the extent and disposition of the Utility's under-collected costs, if any, remaining at the end of the rate freeze. If the CPUC determines that the Utility recovered revenues in excess of its transition costs or in excess of other permitted uses, the CPUC may require the Utility to refund such excess revenues.

In a case currently pending before it relating to the CPUC's settlement with Southern California Edison (SCE), another California IOU, the Supreme Court of California is considering whether the CPUC has the authority to enter into a settlement which allows SCE to recover under-collected procurement and transition costs in light of the provisions of AB 1890. The Utility cannot predict the outcome of this case or whether the CPUC or others would attempt to apply any ruling to the Utility. If the Utility is ordered to refund material amounts to ratepayers, the Utility's financial condition and results of operations would be materially adversely affected.

In December 2002, the CPUC issued a decision authorizing the Utility to stop tracking amounts related to the $0.01 per kWh and $0.03 per kWh surcharge revenues as a separate regulatory liability and instead record them as a reduction of under-collected purchased power costs and transition costs. As a result, in January 2003, the Utility filed a letter with the CPUC requesting to withdraw its regulatory liability account used to track $0.01 per kWh and $0.03 per kWh surcharge revenues in excess of ongoing procurement costs.

Based on this December 2002 CPUC decision and an agreement between the CPUC and SCE, in which SCE was allowed to use its half-cent surcharge to offset its DWR revenue requirement, the Utility reversed its $222 million of regulatory liabilities related to the $0.01 per kWh and $0.03 per kWh surcharge revenues and the $0.005 per kWh surcharge revenues during the fourth quarter of 2002. (Of this amount, $157 million was originally recorded as a regulatory liability during 2002; as such, the reversal of this amount has no impact on current year earnings).

1999 GRC

Through a GRC proceeding, 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.

The 1999 GRC decision ordered an audit to assess the contribution of the Utility's 1999 electric and gas distribution capital additions to system reliability, capacity, and adequacy of service. The audit began in February 2002 and a final report was issued on November 8, 2002. The final report concludes, "in general the [Utility's] 1999 overall capital expenditure program appears quite acceptable." The final report offers recommendations to improve the Utility's distribution capital investment process, but recommends no adjustments to the Utility's distribution rate base.

In October 2001, the CPUC reopened the record in the 1999 GRC to review the Utility's actual 1998 capital spending on electric distribution compared with the forecast used to determine 1999 rates. This would result in an adjustment of the adopted 1998 capital spending forecast level to conform to the 1998 recorded level. The Utility does not expect a material impact on its financial position or results of operations from the remaining proceedings.

On December 1, 2002, the CPUC issued a decision further modifying the 1999 GRC decision that prospectively adopted a $10.6 million downward annual adjustment to supervision costs in customer records and collection expenses. There was no material impact on the Utility's financial position or results of operations.

2003 GRC

In the 2003 GRC, the CPUC will determine the amount of authorized base revenues the Utility can collect from ratepayers to recover its basic business and operational costs for gas and electric distribution operations for 2003 through 2005. On November 8, 2002, the Utility requested a $447 million increase in its electric distribution revenue requirements and a $105 million increase in its gas distribution revenue requirements, over the current authorized amounts. The Utility also will seek an attrition rate adjustment (ARA) increase for 2004 and 2005. The ARA mechanism is designed to avoid a reduction in earnings in years between GRCs to reflect increases in rate base and expenses.

The electric distribution revenue requirement increase would not increase overall bundled electric rates over their current authorized levels. However, the gas bill for a typical residential customer would rise by approximately 2.6 percent or $0.99 per month.

Additionally, as directed by the CPUC in the Utility's 2002 retained generation proceeding (see "Retained Generation Revenue Requirement" above), the Utility submitted testimony supporting the costs of operating the Utility's generation facilities and fuel and purchased power costs. The Utility requested an increase of approximately $61 million over the interim 2002 retained generation revenue requirement authorized by the CPUC. On October 25, 2002, the CPUC issued a decision ordering the Utility to resume the procurement function on January 1, 2003. That decision also directed the Utility to amend its GRC application to remove certain generation-related fuel and purchased power costs from its GRC and instead to include them in another CPUC proceeding. In its GRC, the Utility forecasts a decrease in these costs in 2003. This decrease offsets the forecast increase in costs to operate the Utility's generation facilities. Removing the fuel and purchase power from the generation-related revenue requirement set forth in the GRC would result in an increase in the forecast generation-related revenue requirement of approximately $80 million to $90 million.

On December 17, 2002, the CPUC granted the Utility's request that the revenue requirement established in the 2003 GRC be effective January 1, 2003, even though the CPUC will not issue a final decision on the 2003 GRC until sometime after that date.

The Utility cannot predict what amount of revenue requirements, if any, the CPUC will authorize for the 2003 through 2005 period. The CPUC Commissioner assigned to the 2003 GRC has adopted a schedule for this proceeding that includes a target date for a final decision of February 5, 2004.

2002 ARA Request

In April 2002, the CPUC conditionally authorized a request by the Utility for interim attrition relief and made any attrition relief ultimately granted effective as of April 22, 2002. In June 2002, the Utility filed its 2002 ARA application, requesting a $76.7 million increase to its annual electric distribution revenue requirement, and a $19.5 million increase to its annual gas distribution revenue requirement. In December 2002, a proposed decision was issued that would deny this request. The Utility filed comments in late December 2002 arguing that the proposed decision was based on a fundamental misunderstanding of the facts. In February 2003, an alternate proposed decision was issued that would grant a $63.5 million increase to the Utility's annual electric distribution revenue requirement, and a $10.3 million increase to the Utility's annual gas distribution revenue requirement. A final decision is expected to be issued in the first quarter of 2003.

In the 2003 GRC, the CPUC asked parties to comment on the Utility's need for a 2002 ARA proceeding. The Utility informed the CPUC in November 2001 that the Utility would need a 2002 ARA to recover escalating electric and gas distribution service costs.

Cost of Capital Proceedings

Each year, the Utility files an application with the CPUC to determine the authorized rate of return the Utility may earn on its electric and gas distribution assets.

On November 7, 2002, the CPUC issued a final decision in the Utility's 2003 Cost of Capital proceeding that retained the Utility's return on common equity (ROE) at the current authorized level of 11.22 percent. This final decision also increased the Utility's authorized cost of debt to 7.57 percent from 7.26 percent, and held in place the current authorized capital structure of 48 percent common equity, 46.2 percent long-term debt, and 5.8 percent equity. The final decision also holds open the case to address the impact on the Utility's ROE, costs of debt and preferred stock, and ratemaking capital structure of the implementation and financing of a bankruptcy plan of reorganization. The Utility is required to file an advice letter within 30 days of completing any such financing to request authority to true up its test year 2003 ratemaking capital structure, long-term debt and preferred stock cost, risks, and ROE. The Utility does not expect a material impact on the Utility's financial position or results of operations from the remaining proceedings.

FERC Prospective Price Mitigation Relief

In response to the unprecedented increase in wholesale electricity prices during 2000 and 2001, the FERC issued a series of orders in the spring and summer of 2001 and July 2002 aimed at mitigating future extreme wholesale energy prices. These orders established a cap on bids for real-time electricity and ancillary services of $250 per megawatt-hour (MWh) and established various automatic mitigation procedures. Recently, the FERC proposed to adopt a safety net bid cap as part of the mitigation plan for wholesale energy markets and has requested comments on the appropriate value for such a bid cap.

Also, in June and July 2001, the FERC's chief administrative law judge conducted settlement negotiations among power sellers, the State of California, and the California IOUs in an attempt to resolve disputes regarding past electric sales. Various parties, including the Utility and the State of California, are seeking up to $8.9 billion in refunds for electricity overcharges on behalf of buyers. The negotiations did not result in a settlement, but the judge recommended that the FERC conduct further hearings to determine possible refunds and what the power sellers and buyers are each owed. On December 12, 2002, a FERC administrative law judge issued an initial decision finding that power companies overcharged the utilities, the State of California and other buyers from October 2, 2000 to June 2001 by $1.8 billion, but that California buyers still owe the power companies $3 billion, leaving $1.2 billion in unpaid bills. The time period reviewed in the FERC hearings excludes the claims for refunds for overcharges that occurred before October 2, 2000, and after June 2001 when the DWR entered into contracts to buy electricity. Additional hearings are scheduled to conclude in February 2003.

The Utility has recorded $1.8 billion of generator claims made in its bankruptcy case as Liabilities Subject to Compromise. If the FERC administrative law judge's initial recommendation is upheld by the FERC, these claims would be reduced to approximately $1 billion based on the re-calculation of market prices according to the refund methodology recommended in the initial decision. After the FERC considers any additional evidence that may be presented, if the FERC determines that time periods before October 2, 2000, should be considered, or that additional market transactions or a different refund methodology are appropriate, such decisions could materially increase or decrease the amount of generator claims for which the Utility is determined to be liable. The Utility cannot predict the ultimate amount of generator claims for which it could be liable. The Utility also sold generation into the ISO and PX markets in the relevant time period. The amount of generator claims for which the Utility is determined to be liable would be net of any amounts owed to the Utility for such sales. The Utility cannot predict when the FERC will issue a decision, nor can it predict whether a refund will be ordered or the amount the Utility might receive.

FERC Transmission Rate Cases

Electric transmission revenues and both wholesale and retail transmission rates are regulated by the FERC. On January 29, 2003, the FERC approved a settlement that allows the Utility to recover in electric transmission rates $292 million on an annual basis from March 31, 1998, until October 29, 1998, and $316 million on an annual basis from October 30, 1998, until May 30, 1999. During that period, somewhat higher rates were collected, subject to refund. As a result of this settlement, the Utility will refund $30 million it had accrued for potential refunds related to the 14-month period ended May 30, 1999. The transmission rates charged to electric retail and new wholesale transmission customers are adjusted for other transmission revenue credits related to ISO congestion management charges and other transmission-related services billed by the ISO and remitted to the Utility as a transmission owner.

The Utility currently has other transmission rate cases pending with the FERC including:

- An application that would allow the Utility to recover $545 million in electric retail transmission rates annually. Filed on January 13, 2003, the 44 percent increase over the revenue requirement currently in effect is mainly attributable to significant capital additions made to the Utility's transmission system to accommodate load growth, to maintain the infrastructure, and to ensure safe and reliable service. In addition, the request includes a 15-year useful life for transmission plant coming into service in 2003 and a return on equity of 13.5 percent. The January 13 filing date will allow proposed rates to go into effect, subject to refund, no later than August 13, 2003; and

- A proposal for the FERC to increase the Utility's electricity and transmission-related rates charged to the WAPA. The majority of the requested increase is related to passing through market electricity 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. The FERC denied this request, as well as a request for a rehearing. The Utility has appealed the denial of its request for a rehearing 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, the Utility will continue to calculate WAPA's rates on a yearly basis using the formula specified in WAPA's contract. 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. The Utility cannot estimate the difference between its cost to meet its obligations to WAPA and revenues it receives from WAPA because both the purchase price and the amount of energy that WAPA will need from the Utility through the end of the contract are uncertain.

Scheduling Coordinator Costs

The Utility serves as the scheduling coordinator to schedule transmission with the ISO for the Utility's existing wholesale transmission customers. 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." These costs historically have been tracked in the transmission revenue balancing account (TRBA) in order to recover these costs from retail and new wholesale transmission customers (TO Tariff customers).

On August 5, 2002, the FERC ruled that the Utility should refund to TO Tariff customers the scheduling coordinator costs that the Utility collected from them. In November 2002, the FERC denied the Utility's request for rehearing. On December 9, 2002, the Utility appealed the

FERC's decision in the U.S. Court of Appeals for the D.C. Circuit. In the absence of an order from the FERC granting recovery of these costs in the TRBA, the Utility has made accounting entries to reflect the SC costs as accounts receivable under the Scheduling Coordinator Services (SCS) Tariff described below.

In January 2000, the FERC accepted a filing by the Utility to establish the SCS Tariff. The SCS Tariff was filed to serve as an alternative mechanism for recovery of the SC costs from existing wholesale customers if the Utility was ultimately unable to recover these costs 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 was issued regarding the inclusion of SC costs in the TRBA. In September 2002, the Utility filed a notice with the FERC indicating its intent to request that the FERC resume the SCS Tariff proceeding if the request for rehearing of the FERC's August 5 order was not granted. For the period beginning April 1998 through December 31, 2002, the Utility transferred $107 million of scheduling coordinator costs from the TRBA to accounts receivable net of a $66 million reserve for potential uncollectible costs. The Utility also has disputed approximately $27 million of these costs as incorrectly billed by the ISO. Any refunds that ultimately may be made by the ISO would offset the accounts receivable and corresponding reserve.

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

In 1998, the Utility implemented a ratemaking pact called the Gas Accord, separating its gas transportation and storage services from its distribution services, and changing the terms of service and rate structure for gas transportation. The Gas Accord allows residential and small commercial customers (core customers) to purchase gas from competing suppliers, establishes an incentive mechanism whereby the Utility recovers its core procurement costs, and establishes gas transportation rates through 2002 and gas storage rates through March 2003. Under the Gas Accord, the Utility is at-risk for recovery of its gas transportation and storage costs and does not have regulatory balancing account protection for over- or under-collections of revenues. Under the Gas Accord, the Utility sells a portion of the transportation and storage capacity at competitive market-based rates. Revenues are sensitive to changes in the weather, natural gas fired generation and price spreads between two delivery or pricing points.

On October 9, 2001, the Utility asked the CPUC to extend the terms and conditions of the existing Gas Accord for two years and to maintain current gas transportation and storage rates during the extension.

In August 2002, the CPUC approved a settlement agreement among the Utility and other parties that provided for a one-year extension of its existing gas transportation and storage rates. The settlement also provided for a one-year extension of terms and conditions of service, including the Core Procurement Incentive Mechanism (for further discussion see "Utility Natural Gas Commodity Price Risk"), as well as rules governing contract extensions and an open season for new contracts. The Gas Accord II settlement left open to subsequent litigation the issues raised in the application in so far as they relate to the second year of the two-year application.

In October 2002, the assigned CPUC administrative law judge issued a ruling that granted, in part, the Utility's motion to postpone the procedural schedule for litigation of the unresolved issues. In

January 2003, the Utility filed an amended application proposing to permanently retain the Gas Accord market structure, and requested a $55 million increase in the Utility's gas transmission rates for 2004 and storage rates for the period from April 1, 2004, to March 31, 2005. This request represents a 12.9 percent increase in the Utility's revenue requirement and a 13.4 percent return on equity.

The existing gas transportation and storage rates will continue until the CPUC approves such changes. The Gas Accord II proposal includes rates set based on a demand or throughput forecast basis. In addition it proposes that, at the beginning of the adopted Gas Accord II agreement period, a contract extension and an open season be held for any uncontracted capacity rights. The Utility may experience a material reduction in operating revenues (1) if the Utility were unable to renew or replace existing transportation contracts at the beginning or throughout the Gas Accord II period, (2) the Utility were to renew or replace those contracts on less favorable terms than adopted by the CPUC, or (3) overall demand for transportation and storage services were less than adopted by the CPUC in setting rates. In any of these cases, the Utility's financial condition and results of operations could be adversely affected.

The Utility cannot predict what the outcome of this litigation will be, or whether the outcome will have a material adverse effect on its results of operations or financial condition.

El Paso Capacity Decision

In May 2002, the FERC directed El Paso Natural Gas Company (El Paso) to change the way it allocates space on its pipeline. The order required shippers east of California with capacity rights on El Paso's pipeline to convert their capacity rights from unlimited "full requirement" to a limited contract demand amount of firm capacity. These shippers had to decide by July 31, 2002, how much El Paso capacity they would need in demand contracts and how much capacity they would give up.

In July 2002, the CPUC required California IOUs to sign up for El Paso pipeline capacity given up by the shippers and not subscribed to by replacement shippers serving California. The CPUC pre-approved such costs as just and reasonable. The decision stated that this requirement would spread El Paso reservation charges over as many ratepayers as possible to minimize the impact on any particular utility's customers.

The decision also addressed current capacity issues. It ordered the utilities to retain their current capacity levels on any interstate pipeline and to sell any excess capacity to a third party under short-term capacity release arrangements. To the extent the utilities comply with the decision, they will be able to fully recover their costs associated with existing capacity contracts.

In Phase II of this proceeding, the CPUC is addressing other issues that relate to these proposed rules, including (1) cost allocation of the El Paso capacity among the Utility's customers, (2) short-term capacity releases, and (3) details about the guaranteed rate recovery of the utilities' costs for subscription to interstate pipeline capacity. Phase II hearings are scheduled for the end of April 2003.

Since the July CPUC decision, the Utility has signed contracts for capacity on El Paso totaling approximately $50.8 million beginning November 2002 through December 2007, assuming no contracts set to expire before the end of 2007 are extended. The Utility has filed with the CPUC to recover both prepayments made to El Paso and ongoing capacity costs on the El Paso and the Transwestern Pipeline Company (Transwestern) pipelines. Under a previous CPUC decision, the Utility could not recover any costs paid to Transwestern for gas pipeline capacity through 1997. The Gas Accord (see "Gas Accord II" above) provided for partial recovery of Transwestern costs during the period 1998 through 2002. However, because of the El Paso decision, the Utility may be authorized to recover its future gas pipeline capacity purchases, which could result in additional revenues to recover costs of approximately $82 million over the remaining contract period that ends in March 2007.

On December 19, 2002, the CPUC issued a resolution that would delay the Utility's recovery of some of these costs. The resolution grants the Utility's request to recover in rates El Paso capacity costs and prepayments made to El Paso, subject to reallocation between customers in Phase II of the proceeding. However, the resolution also ordered the Utility to continue to treat Transwestern capacity

costs as it had prior to the July 2002 CPUC decision. Recovery of Transwestern costs not currently authorized is being addressed in Phase II of the proceeding. The Utility does not expect the outcome of this matter to have a material adverse impact on its financial position or results of operations.

Rate Reduction Bonds

California's electric industry restructuring law (AB 1890) required that retail electric rates for residential and small commercial customers be reduced by 10 percent and frozen at that level until the earlier of March 31, 2002, or when the Utility fully recovered certain costs associated with the transition to a deregulated energy market.

To pay for the 10 percent rate reduction, the legislation authorized the issuance of rate reduction bonds to be repaid by residential and small commercial customers through the collection of a separate non-bypassable charge called the Fixed Transition Amount (FTA). The Utility sold its rights to collect FTA charges to its subsidiary PG&E Funding LLC for $2.9 billion in cash. To fund the purchase, PG&E Funding LLC issued $2.9 billion of rate reduction bonds (see discussion of "Rate Reduction Bonds" in Note 5 of the Notes to the Consolidated Financial Statements). The bonds allow for the rate reduction by lowering the carrying cost on a portion of the Utility's transition costs and by spreading recovery of that reduction over the life of the bonds.

Because of the 10 percent rate reduction, the amount of revenue the Utility had available in its frozen rates to recover its transition costs was reduced. Before the first quarter of 2002, to the extent that transition costs were not recovered because of the 10 percent rate reduction, the Utility deferred these transition costs through the rate reduction bond regulatory asset (RRBRA). The RRBRA will be recovered through future FTA charges.

In the first quarter of 2002, the Utility stopped deferring transition costs into the RRBRA and began amortizing the balance of the RRBRA concurrent with the amortization of the rate reduction bonds debt. The Utility recorded amortization expense of $290 million for the 12 months ended December 31, 2002. The Utility recorded deferred transition costs of $458 million for the 12 months ended December 31, 2001. The balance of the RRBRA was $1,346 million at December 31, 2002, and $1,636 million at December 31, 2001.

The proceeds of the rate reduction bonds included amounts sufficient to pay income taxes that would be levied on future FTA revenues. The Utility benefited from the receipt of this cash up front as it reduced the overall level of financing the Utility was required to maintain. Before the first quarter of 2002, the financing cost benefit was credited to ratepayers through a reduction in the amount of transition costs that were deferred into the RRBRA. When the Utility stopped deferring transition costs into the RRBRA, the Utility began crediting this benefit to a regulatory balancing account. The balance credited to residential and small commercial customers through this account was $102 million at December 31, 2002 and $17 million at December 31, 2001.

Annual Earnings Assessment Proceeding for Energy Efficiency Program Activities

The Utility administers general and low-income energy efficiency programs, and has been authorized to earn 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. Each year the Utility files an earnings claim in the Annual Earnings Assessment Proceeding (AEAP), a forum for stakeholders to comment on, and for the CPUC to verify, the Utility's claim. On March 21, 2002, the CPUC eliminated the opportunity for shareholder incentives in connection with the California utilities' 2002 energy efficiency programs. This decision does not preclude the opportunity to recover shareholder incentives in connection with previous years' energy efficiency programs.

In May 2002, 2001, and 2000, the Utility filed its annual applications claiming incentives of approximately $106 million. The CPUC has delayed action on these proceedings and the Utility has not included any earnings associated with incentives in the Utility's Consolidated Statements of Operations.

On March 13, 2002, an administrative law judge for the CPUC requested comments on whether incentives adopted for pre-1998 energy efficiency programs should be reduced or eliminated for claims in future years. Out of the total $106 million in shareholder incentives claimed by the Utility for its 2002, 2001, and 2000 AEAP filings, $74 million is related to pre-1998 energy efficiency programs. The CPUC has not yet ruled on the comments.

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

Baseline Allowance Increase

In April 2002, the CPUC required the Utility to increase baseline allowances for certain residential customers by May 1, 2002. An increase to a customer's baseline allotment increases the amount of their monthly usage that is covered under the lowest possible rate and is exempt from surcharges. The CPUC deferred consideration of corresponding rate changes until a later phase of the proceeding and ordered the utilities to track the under-collections associated with their respective baseline quantity changes in an interest-bearing balancing account. The Utility estimates the annual revenue shortfall to be approximately $101 million for electric and $11 million for gas. The Utility is charging the electric-related shortfall against earnings because it cannot predict the outcome of the second phase of the proceeding, nor can it conclude that recovery of the electric-related balancing account is probable. The total electric revenue shortfall for the period May through December 2002 was $69.8 million.

Issues that may be resolved during the second phase of the proceeding in early 2003 include items that could involve additional revenues at risk such as demographic revisions to baseline allowances, special allowances, and changes to baseline territories or seasons. The Utility estimated additional annual revenue shortfalls from this second phase, if adopted, of $79.6 million for electric service and $11 million for gas service, plus $11.6 million in administration costs spread out over three to five years. Included in this amount is an estimated $18 million annual shortfall resulting from a settlement allowing common-area electric accounts to switch from residential to commercial rates. The settlement, approved by the CPUC on January 16, 2003, is designed to allow common-area accounts to avoid disproportionately high rate increases caused by the five-tiered residential electric surcharges adopted in June 2001. The new five-tiered residential rate structure resulting from the $0.03 per kWh average surcharge assesses surcharges for usage above 130 percent of a customer's baseline allowance. Because most of the usage of large common area accounts falls within the highest rate tiers, these accounts pay disproportionately high bills as a result of this rate design. By contrast, the Utility's surcharges for commercial customers do not vary based on usage levels. As with the baseline quantity changes from the first phase, the CPUC deferred common area cost allocation and rate design issues to the second phase.

The Utility cannot predict what the outcome of the second phase of the proceeding will be, nor can it conclude that recovery of the electric baseline related balancing account is probable. Any electric revenue shortfalls will continue to be charged to earnings and will reduce revenue available to recover previously written-off under-collected purchased power costs and transition costs.

Nuclear Decommissioning Cost Triennial Proceeding Application

In March 2002, the Utility filed an application to increase the Utility's nuclear decommissioning revenue requirements for the years 2003 through 2005. The Utility seeks to recover $24 million in revenue requirements relating to the Diablo Canyon Nuclear Decommissioning Trusts and $17.5 million in revenue requirements relating to the Humboldt Bay Power Plant Decommissioning Trusts. The Utility also anticipates recovering $7.3 million in CPUC-jurisdictional revenue requirements for Humboldt Bay Unit 3 SAFSTOR (a mode of decommissioning) operating and maintenance costs, and escalation associated with that amount in 2004 and 2005. The Utility proposes continuing to collect the revenue requirement through a charge in electric rates, and to record the revenue requirement and the associated revenues in a balancing account. Until post-rate freeze ratemaking is implemented, the increase in revenue requirements would reduce the amount of revenues available to offset electric generation costs.

The ORA filed testimony with the CPUC that included lower estimates on contingencies, escalation rates and the cost of disposal of low-level radioactive wastes, and a higher estimate for returns on investments in the Decommissioning Trusts. If ORA's estimates were adopted, the Utility would not need to make any new contributions to the Decommissioning Trusts for the years 2003 through 2005, since the current amounts in the Decommissioning Trusts would be adequate to pay for expected decommissioning activities. The CPUC held hearings in September 2002 and is expected to reach a final decision during April 2003.

ADDITIONAL SECURITY MEASURES

Since the September 11, 2001, terrorist attacks, PG&E Corporation and the Utility have been working to assess the need for physical security upgrades at critical facilities. Various federal regulatory agencies have issued orders requiring additional safeguards, including a May 2002 Nuclear Regulatory Commission, or NRC, order. The NRC order required decommissioned nuclear facilities, such as the Utility's Humboldt Bay Power Plant, to implement interim security compensatory measures. Facilities affected by PG&E Corporation's and the Utility's assessments include generation facilities, transmission substations, and gas transmission facilities. The security upgrades will require additional capital investment and an increased level of operating costs. However, neither PG&E Corporation nor the Utility believes these costs will have a material impact on their consolidated financial position or results of operations.

RISK MANAGEMENT ACTIVITIES

PG&E Corporation and the Utility are exposed to various risks associated with their operations, the marketplace, contractual obligations, financing arrangements and other aspects of their business. PG&E Corporation and the Utility actively manage these risks through risk management programs. These programs are designed to support business objectives, minimize costs, discourage unauthorized risk, and reduce the volatility of earnings and manage cash flows. At PG&E Corporation and the Utility, risk management activities often include the use of energy and financial derivative instruments and other instruments and agreements.

These derivatives include forward contracts, futures, swaps, options, and other contracts.

- A forward contract is a commitment to purchase or sell a fixed amount of a commodity at a specified future date at a specified price;

- A futures contract is a standardized commitment, traded on an organized exchange, to purchase or sell a fixed amount of a commodity at a specified future date at a specified price;

- A swap contract is an agreement between two counterparties to exchange cash flows in the future based on changes in the underlying commodity or index; and

An option contract provides the right, but not the obligation, to buy or sell the underlying asset at a predetermined price in the future.

PG&E Corporation uses derivatives for both non-trading and trading (i.e., speculative) purposes. The Utility uses derivatives for non-trading purposes only.

PG&E Corporation and the Utility may use energy and financial derivatives and other instruments and agreements to mitigate the risks associated with an asset (e.g., the natural position embedded in asset ownership and regulatory arrangements), liability, committed transaction, or probable forecasted transaction. Additionally, PG&E Corporation may engage in trading activities for purposes of generating profit, gathering market intelligence, creating liquidity, and maintaining a market presence. These instruments are used in accordance with approved risk management policies adopted by a senior officer-level risk oversight committee. Derivative activity is permitted only after the risk oversight committee approves appropriate risk limits for such activity. The organizational unit proposing the activity must successfully demonstrate that there is a business need for such activity and that the market risks will be adequately measured, monitored, and controlled.

The activities affecting the estimated fair value of trading activities and the non-trading activities balance, included in net price risk management assets and liabilities, are presented below.

(in millions)	Year Ended December 31,	
	2002	2001
Fair values of trading contracts at beginning of period	$ 58	$ 199
Net (gain) loss on contracts settled during the period	(121)	(296)
Fair value of new contracts when entered into	2	
Changes in fair values attributable to changes in valuation techniques and assumptions	(12)	
Other changes in fair values	51	155
Fair values of trading contracts outstanding at end of period	(22)	58
Fair value of non-trading contracts at the end of the period	(270)	63
Net Price Risk Management Assets (Liabilities) at end of period	(292)	121
Amounts reclassified as net price risk management assets (liabilities) held for sale	(377)	55
Net price risk management assets (liabilities) reported on the Consolidated Balance Sheets	$ 85	$ 66

The changes in fair values attributable to changes in valuation and assumptions, as reported in the table above, are composed of a $14 million loss related to PG&E NEG's implementation of a new methodology for estimating forward prices in illiquid periods, for which price information is not readily available, and a $2 million gain related to changes in assumptions used to value transportation contracts. This change in forward prices is described more fully in Note 1 of the Notes to the Consolidated Financial Statements.

PG&E Corporation estimates the gross mark-to-market value of its non-trading and trading contracts at December 31, 2002, using the midpoint of quoted bid and ask prices, where available.

When market data is not available, PG&E Corporation uses its forward price curve methodology described in Note 1 of the Notes to the Consolidated Financial Statements.

The gross mark-to-market valuation is then adjusted for the time value of money, creditworthiness of contractual counterparties, market liquidity in future periods, and other adjustments necessary to determine fair value. Most of PG&E Corporation's risk management models are reviewed by or purchased from third-party experts in specific derivative applications.

The following table shows the fair value of PG&E Corporation's trading contracts grouped by maturity at December 31, 2002.

(in millions)

	Fair Value of Trading Contracts [1]				
	Maturity Less than One Year	**Maturity One-Three Years**	**Maturity Four-Five Years**	**Maturity in Excess of Five Years**	**Total Fair Value**
Source of Prices Used in Estimating Fair Value					
Actively quoted markets [2]	$ 6	$ 10	$	$	$ 16
Provided by other external sources	(26)	7	(13)	(3)	(35)
Based on models and other valuation methods [3]	(23)	(30)	(15)	65	(3)
Total Mark-to-Market	$ (43)	$ (13)	$ (28)	$ 62	$ (22)

(1) Excludes all non-trading contracts, including non-trading contracts that receive mark-to-market accounting treatment.

(2) Actively quoted markets are exchanged traded quotes.

(3) In many cases, these prices are an input into option models that calculate a gross mark-to-market value from which fair value is derived.

The amounts disclosed above are not indicative of likely future cash flows. The future value of trading contracts may be impacted by changes in underlying valuations, new transactions, market liquidity, and PG&E Corporation's risk management portfolio needs and strategies.

Market Risk

Market risk is the risk that changes in market conditions will adversely affect earnings or cash flow.

PG&E Corporation categorizes market risks as price risk, interest rate risk, foreign currency risk, and credit risk. These market risks may impact PG&E Corporation's and its subsidiaries' assets and trading portfolios. Immediately below is an overview of PG&E Corporation's market risks, followed by detailed descriptions of the market risks and explanations as to how each of these risks are managed.

- Price risk results from the Utility's or PG&E NEG's exposure to the impacts of market fluctuations in price and transportation costs of commodities such as electricity, natural gas, other fuels, and other energy-related products;

- Interest rate risk primarily results from exposure to the volatility of interest rates as a result of financing or refinancing through the issuance of variable-rate and fixed-rate debt;

- Foreign currency risk results from exposure to volatilities in currency rates; and

- Credit risk results from exposure to counterparties who may fail to perform under their contractual obligations.

Price Risk

Price risk is the risk that changes in primarily commodity market prices will adversely affect earnings and cash flows. Below are descriptions of the Utility's and PG&E NEG's specific price risks.

Also described below is the value-at-risk methodology, which is PG&E Corporation's and the Utility's method for assessing the prospective risk that exists within a portfolio for price risk.

Utility Electric Commodity Price Risk

Purchased Power

In compliance with regulatory requirements, the Utility manages commodity price risk independently from the activities in PG&E Corporation's unregulated businesses. The Utility also reports its commodity price risk separately for its electric and natural gas businesses.

Since January 2001, the DWR has been responsible for procuring electricity required to cover the Utility's net open position. The Utility bills its customers for these DWR electricity purchases and remits amounts collected to the DWR based on their CPUC approved revenue requirement. To the extent that the Utility's electricity rates remain frozen, and the CPUC increases the portion of the DWR's revenue requirement allocated to the Utility's customers to cover adverse market price changes or other factors, the Utility has commodity price risk. The Utility is exposed to price risk to the extent that the cost of new electricity purchases increases, or the revenue from new wholesale sales decreases.

The DWR's authority to enter into new electricity purchase contracts expired January 1, 2003. SB 1976 and CPUC orders required the California IOUs, including the Utility, to resume responsibility for procuring the electricity to meet the residual net open position by January 1, 2003.

On December 19, 2002, the CPUC issued an interim opinion granting the Utility authority to enter into contracts designed to hedge the residual net open position through the first quarter of 2004. The CPUC's interim opinion also established a maximum annual procurement disallowance equal to twice the Utility's annual administrative costs of managing procurement activities, including the administration and dispatch of electricity associated with DWR allocated contracts. However, the Utility can provide no assurance that the CPUC will not increase or eliminate this maximum annual

procurement disallowance in the future. Such a change would increase the Utility's exposure to electric commodity price risk.

The residual net open position is expected to increase over time due to periodic expirations of existing and DWR allocated procurement contracts. The Utility can provide no assurance that electricity will continue to be available for purchase in quantities sufficient to satisfy the residual net open position as these or other events occur. Even if the Utility were able to purchase electricity in quantities sufficient to satisfy the residual net open position, it would be exposed to wholesale electricity commodity price fluctuations and uncertain commercial terms.

Conversely, the amount of energy provided by the DWR contracts will likely result in significant excess electricity during various periods, which the Utility will be required to attempt to sell on the open market.

Nuclear Fuel

The Utility has purchase agreements for nuclear fuel components and services for use in operating the Diablo Canyon generating facility. 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 information. In January 2002, the U.S. International Trade Commission imposed tariffs of up to 50 percent on imports from certain countries providing nuclear fuel. If these tariffs remain in place, the Utility's nuclear fuel costs may rise because there are a limited number of suppliers in the world for such fuel. The Utility's ratemaking for retained generation is cost-of-service-based; however, to the extent that the Utility's electricity rates remain frozen, changes in the cost of nuclear fuel would impact the amount of revenues the Utility has available to recover its previously written-off under-collected purchased electric generation costs. For this reason, the Utility is exposed to price risk to the extent that the cost of nuclear fuel increases.

Utility Natural Gas Commodity Price Risk

Through 2003, the Core Procurement Incentive Mechanism (CPIM) determines how much of the cost of procuring natural gas for its customers may be included in the Utility's natural gas procurement rates. Under the CPIM, the Utility's procurement costs are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas prices at the points where the Utility typically purchases natural gas. If costs fall within a range, or tolerance band currently 99 percent to 102 percent, around the benchmark, they are considered reasonable and may be fully recovered in customer rates. Ratepayers and shareholders share equally the costs and savings outside the tolerance band.

In addition, the Utility has contracts for transportation capacity on various natural gas pipelines. A recent CPUC decision found that the Utility's acquisition of additional interstate transportation capacity was reasonable and that all interstate transportation capacity already held by the Utility was also reasonable. A future decision will allocate the cost of the transportation capacity between customer groups and will also determine the date on which all transportation capacity costs held by the Utility prior to July 2002 will be recoverable.

Under the Gas Accord, shareholders are at risk for any revenues from the sale of capacity on the Utility's gas transmissions and storage facilities. Under the Gas Accord, the Utility sells a portion of the pipeline and storage capacity at competitive market-based rates. Revenues are generally lower when throughput volumes are lower than expected and when the price spreads between two delivery points narrow. In August 2002, the CPUC approved a settlement agreement between the Utility and other parties that provided for a one-year extension of the Utility's existing gas transmission and storage rates and terms and conditions of service through the end of 2003. (The Gas Accord was originally scheduled to expire on December 31, 2002.) For further discussion, see "Gas Accord II" in the "Regulatory Matters" section of the MD&A.

PG&E NEG Price Risk

PG&E NEG is exposed to price risk from its portfolio of proprietary trading contracts and its portfolio of electric generation assets and supply contracts that serve wholesale and industrial customers, and various merchant plants currently in development and construction.

As described above, PG&E NEG is in the process of reducing and unwinding its trading positions. Additionally, asset hedge positions associated with the merchant plants will either remain with the assets or be terminated. PG&E NEG has significantly reduced their energy trading operations in an ongoing effort to raise cash and reduce debt. PG&E NEG's objective is to limit its asset trading and risk management activities to only what is necessary for energy management services to facilitate the transition of PG&E NEG's merchant generation facilities through their sale, transfer, or abandonment process. PG&E NEG will then further reduce and transition to only retain limited capabilities to ensure fuel procurement and power logistics for PG&E NEG's retained independent power plant operations.

Value-at-Risk

PG&E Corporation and the Utility measure price risk exposure using value-at-risk and other methodologies that simulate future price movements in the energy markets to estimate the probability of future potential losses. Price risk is quantified using what is referred to as the variance-covariance technique of measuring value-at-risk, which provides a consistent measure of risk across diverse energy markets and products. This methodology requires the selection of a number of important assumptions including a confidence level for losses, price volatility, market liquidity, and a specified holding period. This technique uses historical price movements data and specific, defined mathematical parameters to estimate the characteristics of and the relationships between components of assets and liabilities held for price risk management activities. PG&E Corporation therefore uses the historical data for calculating the expected price volatility of its portfolio's contractual positions to project the likelihood that the prices of those positions will move together.

The value-at-risk model includes all of PG&E Corporation's and the Utility's commodity derivatives and other financial instruments over the entire length of the terms of the transactions in the trading and non-trading portfolios. PG&E Corporation's and the Utility's value-at-risk calculation is a dollar amount reflecting the maximum potential one-day loss in the fair value of their portfolios due to adverse market movements over a defined time horizon within a specified confidence level. This calculation is based on a 95 percent confidence level, which means that there is a 5 percent probability that PG&E Corporation's portfolios will incur a loss in value in one day at least as large as the reported value-at-risk. For example, if the value-at-risk is calculated at $5 million, there is a 95 percent probability 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. There would also be a 5 percent probability that a one-day price movement would be greater than $5 million.

The following table illustrates the potential one-day unfavorable impact for price risk as measured by the value-at-risk model, based on a one-day holding period. A two-year comparison of daily value-at-risk is included in order to provide context around the one-day amounts. The high and low valuations represent the highest and lowest of the values during 2002. The average valuation represents the average of the values during 2002.

(in millions)	December 31,		Year Ended December 31, 2002		
	2002	2001	Average	High	Low
Utility					
Non-trading activities (1)	$ 4.0	$ 3.6	$ 2.1	$ 5.8	$ 0.3
PG&E NEG					
Trading activities	8.2	5.8	5.2	9.7	2.1
Non-trading activities:					
Non-trading contracts that receive mark-to-market accounting treatment (2)	2.7		2.9	3.9	2.1
Non-trading contracts accounted for as hedges (3)	9.4	10.3	12.5	18.6	9.4

(1) Includes the Utility's gas portfolio only, as this represents the Utility's only commodity price risk through year end 2002.

(2) Includes derivative power and fuels contracts that do not qualify under the SFAS No. 133 normal purchases and normal sales exception and do not qualify to be accounted for as cash flow hedges.

(3) Includes only the risk related to the derivative instruments that serve as hedges and does not include the related underlying hedged item. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the hedged commodity positions, which are not included.

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 and legislative risks currently facing the Utility or the risks relating to the Utility's bankruptcy proceedings.

PG&E NEG's value-at-risk levels have increased at December 31, 2002, as compared to levels at December 31, 2001, due to strong prices and increased market volatility across all commodities in 2002. It is expected that PG&E NEG's value-at-risk levels will eventually peak and start to decrease because, as previously discussed, PG&E NEG is in the process of reducing and unwinding its trading positions. Additionally, asset hedge positions associated with the merchant plants will either remain with the assets or be terminated. See the discussion above in the MD&A's "Liquidity and Financial Resources PG&E NEG" section for further information regarding PG&E NEG's current financial situation.

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates could adversely affect earnings or cash flows. Specific interest rate risks for PG&E Corporation and the Utility include the risk of increasing interest rates on working capital facilities, variable rate tax-exempt pollution control bonds, and other variable rate debt.

PG&E Corporation may use 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 risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2002, if interest rates changed by 1 percent for all variable rate debt at PG&E Corporation and the Utility, the change would affect net income by approximately $35 million for PG&E Corporation and $33 million for the Utility, based on variable rate debt and hedging derivatives and other interest rate-sensitive instruments outstanding.

The table included above in this MD&A's Commitments and Capital Expenditures section provides the maturity of the carrying amounts and the related weighted average interest rates on PG&E Corporation's interest bearing securities, by expected maturity dates.

Foreign Currency Risk

Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies in relation to the U.S. dollar.

PG&E Corporation and the Utility are exposed to such risk associated with foreign currency exchange variations related to Canadian-denominated purchase and swap agreements. PG&E Corporation is also exposed to foreign currency risk resulting from the need to translate Canadian-denominated financial statements of an affiliate into U.S. dollars in the PG&E Corporation Consolidated Financial Statements. PG&E Corporation and the Utility use forwards, swaps, and options to hedge foreign currency exposure.

For the Utility, changes in gas purchase costs due to fluctuations in the value of the Canadian dollar would be passed through to customers in rates, as long as the overall costs of purchasing gas are within a 99 percent to 102 percent tolerance band of the benchmark price under the CPIM mechanism, as discussed above. The Utility's customers and shareholders would share in the costs or savings outside of the tolerance band equally.

PG&E Corporation and the Utility use sensitivity analysis to measure their exchange rate exposure to the Canadian dollar. Based on a sensitivity analysis at December 31, 2002, 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 failed to perform their contractual obligations (these obligations are reflected as Accounts Receivable Customers, net; notes receivable included in Other Noncurrent Assets Other; Price Risk Management (PRM) assets; and Assets held for sale on the balance sheet). PG&E Corporation and the Utility conduct business primarily with customers or vendors, referred to as counterparties, in the energy industry. These counterparties include other investor-owned utilities, 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 because their counterparties may be similarly affected by economic or regulatory changes or other changes in conditions.

PG&E Corporation and the Utility manage their credit risk in accordance with their respective Risk Management Policies. The policies establish processes for assigning credit limits to counterparties before entering into agreements with significant exposure to PG&E Corporation and the Utility. These processes 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 the exposure, or obtain additional collateral, or both. Further, PG&E Corporation and the Utility rely heavily on master agreements that require the counterparty to post security, referred to as credit collateral, in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

PG&E Corporation and the Utility calculate gross credit exposure for each counterparty as the current mark-to-market value of the contract (that is, the amount that would be lost if the counterparty defaulted today) plus or minus any outstanding net receivables or payables, prior to the application of the counterparty's credit collateral.

In 2002, PG&E Corporation's and the Utility's credit risk increased due in part to downgrades of some counterparties credit ratings to levels below investment grade. The downgrades increase PG&E Corporation's or the Utility's credit risk because any collateral provided by these counterparties in the form of corporate guarantees or eligible securities may be of lesser or no value. Therefore, in the event

these counterparties failed to perform under their contracts, PG&E Corporation and the Utility may face a greater potential maximum loss. In contrast, PG&E Corporation and the Utility do not face any additional risk if counterparties' credit collateral is in the form of cash or letters of credit, as this collateral is not affected by a credit rating downgrade.

For the year ended December 31, 2002, PG&E Corporation and the Utility have recognized no losses due to the contract defaults or bankruptcies of counterparties. However, in 2001, PG&E Corporation terminated its contracts with a bankrupt company, which resulted in a pre-tax charge to earnings of $60 million related to trading and non-trading activities, after application of collateral held and accounts payable.

At December 31, 2002, and at December 31, 2001, PG&E Corporation had no single counterparty that represented greater than 10 percent of PG&E Corporation's net credit exposure. At December 31, 2002, the Utility had one investment grade counterparty that represented 21 percent of the Utility's net credit exposure, and one below investment grade counterparty that represented 11 percent of the Utility's net credit exposure. At December 31, 2001, the Utility had no single counterparty that represented greater than 10 percent of the Utility's net credit exposure.

The schedule below summarizes PG&E Corporation's and the Utility's credit risk exposure to counterparties that are in a net asset position, with the exception of exchange-traded futures (the exchange provides for contract settlement on a daily basis), as well as PG&E Corporation's and the Utility's credit risk exposure to counterparties with a greater than 10 percent net credit exposure, at December 31, 2002, and December 31, 2001:

(in millions)	Gross Credit Exposure Before Credit Collateral(1)	Credit Collateral(2)	Net Credit Exposure(2)	Number of Counterparties >10%	Net Exposure of Counterparties >10%
At December 31, 2002					
PG&E Corporation	$ 1,165	$ 195	$ 970		$
Utility (3)	288	113	175	2	55
At December 31, 2001					
PG&E Corporation	$ 1,203	$ 207	$ 996		$
Utility (3)	271	127	144		

(1) Gross credit exposure equals mark-to-market value (adjusted for applicable credit valuation adjustments), notes receivable, and net (payables) receivables where netting is allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value, liquidity, or model.

(2) Net credit exposure is the gross credit exposure minus credit collateral (cash deposits and letters of credit).

(3) The Utility's gross credit exposure includes wholesale activity only. Retail activity and payables incurred prior to the Utility's bankruptcy filing are not included. Retail activity at the Utility consists of the accounts receivable from the sale of gas and electricity to millions of residential and small commercial customers.

At December 31, 2002, approximately $205 million, or 21 percent of PG&E Corporation's net credit exposure was to entities that had credit ratings below investment grade. At December 31, 2002, approximately $64 million, or 37 percent of the Utility's net credit exposure was to entities that had credit ratings below investment grade. At December 31, 2001, approximately $244 million, or 25 percent of PG&E Corporation's net credit exposure was to entities that had credit ratings below investment grade. At December 31, 2001, approximately $32 million, or 22 percent of the Utility's net credit exposure was to entities that had credit ratings below investment grade. Investment grade is determined using publicly available information, i.e., rated at least Baa3 by Moody's and BBB- by S&P. If the counterparty provides a guarantee by a higher rated entity (e.g., its parent), the credit rating determination is based on the rating of its guarantor.

At December 31, 2002, approximately $65 million, or 7 percent of PG&E Corporation's net credit exposure was with counterparties at PG&E NEG that are not rated. At December 31, 2001, none of PG&E Corporation's net credit exposure was with counterparties at PG&E NEG that were not rated. Most counterparties with no credit rating are governmental authorities which are not rated, but which PG&E Corporation has assessed as equivalent to investment grade. Other counterparties with no credit rating are subject to an internal assessment of their credit quality and a credit rating designation.

PG&E Corporation has regional concentrations of credit exposure to counterparties that conduct business primarily in the western United States and also to counterparties that conduct business primarily throughout North America. The Utility has a regional concentration of credit risk associated with its receivables from residential and small commercial customers in northern California. However, the risk of material loss due to nonperformance from these customers is not considered likely. Reserves for uncollectible accounts receivable are provided for the potential loss from nonpayment by these customers based on historical experience. The Utility has a net regional concentration of credit exposure totaling $175 million to counterparties that conduct business primarily throughout North America.

CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Certain of these estimates and assumptions are considered to be Critical Accounting Policies, due to their complexity, subjectivity, and uncertainty, along with their relevance to the financial performance of PG&E Corporation. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

In 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 derivative instruments to be recognized in the financial statements at their fair value. Prior to its rescission, PG&E Corporation accounted for its energy trading activities in accordance with Emerging Issues Task Force (EITF) No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities", and SFAS No. 133, which require certain energy trading contracts to be accounted for at fair values using mark-to-market accounting. See discussion of Rescission of EITF 98-10 below.

Effective for the third quarter ended September 30, 2002, PG&E Corporation adopted the net method of recognizing realized gains and losses on energy trading contracts. Under the net method, revenues and expenses are netted and trading gains (or losses) are reflected in revenues on the income statement, as opposed to reporting revenues and expenses under the previously used gross method.

PG&E Corporation and the Utility have derivative commodity contracts for the physical delivery of purchase and sale quantities such as natural gas and power transacted in the normal course of business. These derivatives are exempt from the requirements of SFAS No. 133 under the normal purchases and sales exception, and are not reflected on the balance sheet at fair value. See further discussion in Notes 1 and 11 of the Notes to the Consolidated Financial Statements.

PG&E Corporation and the Utility apply SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," to their regulated operations. Under SFAS No. 71, regulatory assets represent capitalized costs that would otherwise be charged to expense. These costs are later recovered through regulated rates. Regulatory liabilities are rate actions of a regulator that will later be credited to customers through the rate making process. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. If it is determined that these items are no longer probable of recovery under SFAS No. 71, then they will be written-off at that time. At December 31, 2002, PG&E Corporation reported regulatory assets of $2.2 billion, including current

regulatory balancing accounts receivable and regulatory liabilities of $1.8 billion, including current regulatory balancing accounts payable. See Note 1 of the Notes to the Consolidated Financial Statements.

The Utility records revenues as electricity and natural gas are delivered. A portion of the revenue recognized has not yet been billed. Unbilled revenues are determined by factoring the actual load (energy) delivered with recent historical usage and rate patterns.

Due to the Utility's filing for bankruptcy in 2001, the financial statements for both PG&E Corporation and the Utility are prepared in accordance with SOP 90-7, which is used by reorganizing entities operating under the Bankruptcy Code. Under SOP 90-7, certain claims against the Utility prior to its bankruptcy filing are recorded as Liabilities Subject to Compromise. The Utility reported a total of $9.4 billion of Liabilities Subject to Compromise at December 31, 2002. While the Utility operates under the protection of the Bankruptcy Court, the realization of assets and the liquidation of liabilities is subject to uncertainty, as additional claims to Liabilities Subject to Compromise can change due to such actions as the resolution of disputed claims or certain Bankruptcy Court actions. See Note 2 of the Notes to the Consolidated Financial Statements.

The Utility records an environmental remediation liability when site assessments indicate that remediation is probable and the cost can be reasonably estimated. This liability is based on site investigations, remediation, operations, maintenance, monitoring, and closure. This liability is reviewed on a quarterly basis, and is recorded at the lower range of estimated costs, unless there is a better estimate available. At December 31, 2002, the Utility's undiscounted environmental remediation liability was $331 million. The Utility's future cost could increase to as much as $444 million if (1) the other potentially responsible parties are not financially able to contribute to these costs, (2) the extent of contamination or necessary remediation is greater than anticipated, or (3) the Utility is found to be responsible for clean-up costs at additional sites.

The process of estimating remediation liabilities is difficult and changes in the estimate could occur given the uncertainty concerning the Utility's ultimate liability, the complexity of environmental laws and regulations, the selection of compliance alternatives, and the financial ability of other responsible parties. PG&E NEG estimates that it may be required to spend up to approximately $608 million before insurance proceeds for environmental compliance at certain of its operating facilities. To date, PG&E NEG has spent approximately $13 million on environmental compliance. See Note 16 of the Notes to the Consolidated Financial Statements.

Since the CPUC authorized the collection of incremental surcharge revenues in January and March 2001, the Utility has used generation-related revenues in excess of generation-related costs to recover approximately $1.9 billion (after-tax) in previously written-off under collected purchased power and generation-related charges. For the 12 months ended December 31, 2002, total surcharge revenues recognized were $1.8 billion (after-tax). For the 12 months ended December 31, 2001, total surcharge revenues recognized were $1.3 billion (after-tax). The Utility has not provided reserves for potential refunds of these surcharges as it believes that recent regulatory orders and actions provide evidence that it is not probable that a refund will be ordered. However, it is possible that subsequent decisions by the CPUC may affect the amount and timing of these surcharge revenues recovered by the Utility and that subsequent CPUC decisions may order the Utility to refund all or a portion of the surcharge revenues collected. See Note 2 of the Notes to the Consolidated Financial Statements and risk factors discussed in the Overview section of this MD&A for further discussion. See Note 1 of the Notes to the Consolidated Financial Statements for further discussion of accounting policies and new accounting developments.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Consolidation of Variable Interest Entities In January 2003 the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46), which expands upon existing accounting guidance addressing when a company should include in its

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financial statements the assets, liabilities, and activities of another entity. FIN 46 notes that many of what are now referred to as "variable interest entities" have commonly been referred to as special-purpose entities or off-balance sheet structures. However, the Interpretation's guidance is to be applied to not only these entities but to all entities found within a company. FIN 46 provides some general guidance as to the definition of a variable interest entity. PG&E Corporation is currently evaluating all entities to determine if they meet the FIN 46 criteria as variable interest entities.

Until the issuance of FIN 46, one company generally included another entity in its Consolidated Financial Statements only if it controlled the entity through voting interests. FIN 46 changes that by requiring a variable interest entity to be consolidated by a company if that company is subject to a majority of the risk of loss from the variable interest entity's activities or entitled to receive a majority of the entity's residual returns, or both. A company that consolidates a variable interest entity is now referred to as the "primary beneficiary" of that entity.

FIN 46 requires disclosure of variable interest entities that the company is not required to consolidate but in which it has a significant variable interest.

The consolidation requirements of FIN 46 apply immediately to variable interest entities created after January 31, 2003. The consolidation requirements apply to variable interest entities created before January 31, 2003, in the first fiscal year or interim period beginning after June 15, 2003, so these requirements would be applicable to PG&E Corporation in the third quarter 2003. Certain new and expanded disclosure requirements apply to all financial statements issued after January 31, 2003, regardless of when the variable interest entity was established. These disclosures are required if there is an assessment that it is reasonably possible that an enterprise will consolidate or disclose information about a variable interest entity when FIN 46 becomes effective. PG&E Corporation is currently evaluating the impacts of FIN 46's initial recognition, measurement, and disclosure provisions on its Consolidated Financial Statements.

Guarantor's Accounting and Disclosure Requirements for Guarantees In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 expands on the accounting guidance of SFAS No. 5, "Accounting for Contingencies," SFAS No. 57, "Related Party Disclosures," and SFAS No. 107, "Disclosures about Fair Value of Financial Instruments." FIN 45 also incorporates, without change, the provisions of FASB Interpretation No. 34, "Disclosures of Indirect Guarantees of the Indebtedness of Others," which it supersedes.

FIN 45 elaborates on the existing disclosure requirements for most guarantees. It clarifies that a guarantor's required disclosures include the nature of the guarantee, the maximum potential undiscounted payments that could be required, the current carrying amount of the liability, if any, for the guarantor's obligations (including the liability recognized under SFAS No. 5), and the nature of any recourse provisions or available collateral that would enable the guarantor to recover amounts paid under the guarantee.

FIN 45 also clarifies that at the time a company issues a guarantee, it must recognize an initial liability for the fair value of the obligation it assumes under that guarantee, including its ongoing obligation to stand ready to perform over the term of the guarantee in the event that specified triggering events or conditions occur. This information must also be disclosed in interim and annual financial statements.

FIN 45 does not prescribe a specific account for the guarantor's offsetting entry when it recognizes the liability at the inception of the guarantee, noting that the offsetting entry would depend on the circumstances in which the guarantee was issued. There also is no prescribed approach included for subsequently measuring the guarantor's recognized liability over the term of the related guarantee. It is noted that the liability would typically be reduced by a credit to earnings as the guarantor is released from risk under the guarantee.

The initial recognition and initial measurement provisions apply on a prospective basis to guarantees issued or modified after December 31, 2002. PG&E Corporation is currently evaluating the impact of FIN 45's initial recognition and measurement provisions on its Consolidated Financial Statements. The disclosure requirements for FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002, and have been incorporated into PG&E Corporation's December 31, 2002, disclosures of guarantees.

Rescission of EITF 98-10 In October 2002, the Emerging Issues Task Force rescinded EITF 98-10. Energy trading contracts that are derivatives in accordance with SFAS No. 133 will continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked to market as trading activities under EITF 98-10 that do not meet the definition of a derivative will be recorded at cost, with a one-time adjustment to be recorded as a cumulative effect of a change in accounting principle as of January 1, 2003. For PG&E Corporation, the majority of trading contracts are derivative instruments as defined in SFAS No. 133. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading purposes, which continue to be accounted for in accordance with SFAS No. 133.

The reporting requirements associated with the rescission of EITF 98-10 are to be applied prospectively for all EITF 98-10 energy trading contracts entered into after October 25, 2002. For all EITF 98-10 energy trading contracts in existence at or prior to October 25, 2002, the estimated impact of the first quarter 2003 cumulative effect of a change in accounting principle is a loss of $5 million, net of taxes at December 31, 2002.

Accounting for Costs Associated with Exit or Disposal Activities In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities," which addresses accounting for restructuring and similar costs. SFAS No. 146 supersedes previous accounting guidance, principally EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity" (EITF 94-3). PG&E Corporation will adopt the provisions of SFAS No. 146 for restructuring activities initiated after December 31, 2002. SFAS No. 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF 94-3, a liability for an exit cost was recognized at the date of the company's commitment to an exit plan if certain other criteria were met. SFAS No. 146 also establishes that the liability initially should be measured and recorded at fair value. Accordingly, the prospective implementation of SFAS No. 146 may affect the timing of recognizing future restructuring costs as well as the amounts recognized.

Accounting for Asset Retirement Obligations In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." PG&E Corporation and the Utility will adopt this Statement effective January 1, 2003. SFAS No. 143 provides accounting requirements for costs associated with legal obligations to retire tangible, long-lived assets. 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. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the related asset. Upon adoption, the cumulative effect of applying this Statement will be recognized as a change in accounting principle in the Consolidated Statements of Operations. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this statement and costs recovered through the ratemaking process. Regulatory assets and liabilities may be recorded when it is probable that the asset retirement costs will be recovered through the ratemaking process.

PG&E Corporation estimates the impact of adopting SFAS No. 143 effective January 1, 2003 will be as follows:

- The Utility will adjust its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. The Utility will also recognize asset retirement obligations associated with the decommissioning of other fossil generation assets.

At December 31, 2002, the total nuclear decommissioning obligation accrued was $1.3 billion and is included in accumulated depreciation and decommissioning on the Consolidated Balance Sheets (see Note 13, "Nuclear Decommissioning"). The Utility had accrued, at December 31, 2002, $52 million to decommission certain fossil generation assets based on its estimate of the decommissioning obligation under the accounting principles in effect at that time. These decommissioning obligations are also included in accumulated depreciation and decommissioning on the Consolidated Balance Sheets.

The Utility estimates it will recognize an adjustment to its recorded nuclear and fossil facility decommissioning obligations in the range of an increase of $222 million to a decrease of $192 million for asset retirement obligations in existence as of January 1, 2003. The estimated cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation and decommissioning expense accrued to date will range from a loss of $19 million to a gain of $17 million (pre-tax).

PG&E NEG estimates that it will recognize a liability in the range of $11 million to $21 million for asset retirement obligations on January 1, 2003. The cumulative effect of a change in accounting principle from unrecognized accretion and depreciation expense is estimated to be a loss in the range of $4 million to $6 million (pre-tax).

PENSION AND OTHER POST-RETIREMENT PLANS

PG&E Corporation and its subsidiaries provide qualified and non-qualified non-contributory defined benefit pension plans for their employees, retirees, and non-employee directors. PG&E Corporation and its subsidiaries also 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). Amounts that PG&E Corporation and the Utility recognize as obligations to provide pension benefits under SFAS No. 87, "Employers' Accounting for Pensions," and other benefits under SFAS No. 106. "Employers Accounting for Postretirement Benefits other than Pensions" are based on certain actuarial assumptions. Actuarial assumptions used in determining pension obligations include the discount rate, the average rate of future compensation increases, and the expected return on plan assets. Actuarial assumptions used in determining other benefit obligations include the discount rate, the average rate of future compensation increases, the expected return on plan assets, and the assumed health care cost trend rate. While PG&E Corporation and the Utility believe the assumptions used are appropriate, significant differences in actual experience, plan changes, or significant changes in assumptions may materially affect the recorded pension and other benefit obligations and future plan expenses.

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

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed income returns were based on historic returns for the broad U.S. bond market. Equity returns were determined by applying a market risk premium of 3.5 percent to the U.S. bond market return. For the Utility Retirement Plan, the assumed return of 8.1 percent compares to a ten-year actual return of 8.4 percent.

The rate used to discount pension and other post-retirement benefit plan liabilities was based on a yield curve developed from the Moody's AA Corporate Bond Index at December 31, 2002. This yield curve has discount rates that vary based on the maturity of the obligations. The estimated future cash flows for the pension and other post retirement obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate. The resulting rate was validated by comparison to the yield of a high-quality, non-callable corporate bond portfolio with cash flows corresponding to expected future benefit payments. For the Utility Retirement Plan, a 25 basis point decrease in the discount rate would increase the accumulated benefit obligation by approximately $240 million.

TAXATION MATTERS

The Internal Revenue Service (IRS) has completed its audit of PG&E Corporation's 1997 and 1998 consolidated U.S. federal income tax returns and has assessed additional federal income taxes of $71 million (including interest). PG&E Corporation has filed protests contesting certain adjustments made by the IRS in that audit and currently is discussing these adjustments with the IRS' Appeals Office. The IRS also is auditing PG&E Corporation's 1999 and 2000 consolidated U.S. federal income tax returns, but has not issued its final report. However, the IRS has proposed adjustments totaling $78 million (including interest). The resolution of these matters with the IRS is not expected to have a material adverse effect on PG&E Corporation's earnings. All of PG&E Corporation's federal income tax returns prior to 1997 have been closed. In addition, California and certain other state tax authorities currently are auditing various state tax returns. The results of these audits are not expected to have a material adverse effect on PG&E Corporation's earnings. In the third quarter of 2002, PG&E Corporation re-evaluated its position with respect to the expected realization of certain synthetic fuel tax credits, and as a result, recorded additional tax benefits totaling $43 million.

Deferred tax assets with respect to impairments and write-offs at PG&E NEG were recorded in 2002. Due to uncertainty in realizing state tax benefits associated with these deferred tax assets, valuation allowances were established.

A valuation allowance of $97 million associated with state tax benefits was recorded in continuing operations. In addition, a valuation allowance of $87 million associated with state tax benefits was recorded in discontinued operations.

ENVIRONMENTAL AND LEGAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established both to maintain and to improve the quality of the environment. Where PG&E Corporation's and the Utility's properties contain hazardous substance, these laws and regulations require PG&E Corporation and the Utility to remove those substances or to remedy effects on the environment. Also, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. See Note 16 of the Notes to the Consolidated Financial Statements for further discussion of environmental matters and significant pending legal matters.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk.

Information responding to Item 7A appears under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations Risk Management Activities," and under Notes 1 and 11 of the "Notes to the Consolidated Financial Statements".

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Item 8. Financial Statements and Supplementary Data

PG&E Corporation
CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share amounts)	Year ended December 31,		
	2002	**2001**	**2000**
Operating Revenues			
Utility	$ 10,514	$ 10,462	$ 9,637
Energy commodities and services	1,981	1,748	2,931
Total operating revenues	12,495	12,210	12,568
Operating Expenses			
Cost of electricity and natural gas for utility	2,436	4,606	8,166
Deferred electric procurement cost			(6,465)
Cost of energy commodities and services	1,323	1,047	1,990
Depreciation, amortization, and decommissioning	1,309	1,002	3,595

(in millions, except per share amounts)	Year ended December 31,		
Operating and maintenance	3,373	2,867	3,272
Impairments, write-offs, and other charges	2,767		
Provision for loss on generation-related regulatory assets and under-collected purchased power costs			6,939
Reorganization professional fees and expenses	155	97	
Total operating expenses	11,363	9,619	17,497
Operating Income (Loss)	1,132	2,591	(4,929)
Reorganization interest income	71	91	
Interest income	61	76	214
Interest expense	(1,454)	(1,209)	(788)
Other income (expense), net	90	(31)	(23)
Income (Loss) Before Income Taxes	(100)	1,518	(5,526)
Income tax provision (benefit)	(43)	535	(2,103)
Income (Loss) from Continuing Operations	(57)	983	(3,423)
Discontinued Operations			
Earnings from operations of USGenNE, Mountain View, and ET Canada (net of income taxes of $3 million in 2002, $73 million in 2001, and $75 million in 2000)	11	107	99
Loss on disposal of USGenNE and ET Canada (net of income taxes of $381 million)	(767)		
Loss on disposal of PG&E Energy Services (net of income taxes of $36 million)			(40)
Net Income (Loss) Before Cumulative Effect of Changes in Accounting Principles	(813)	1,090	(3,364)
Cumulative effect of changes in accounting principles (net of income taxes of $42 million in 2002 and $6 million in 2001)	(61)	9	
Net Income (Loss)	$ (874)	$ 1,099	$ (3,364)
Weighted Average Common Shares Outstanding, Basic	371	363	362
Earnings (Loss) Per Common Share, from Continuing Operations, Basic	$ (0.15)	$ 2.71	$ (9.45)
Net Earnings (Loss) Per Common Share, Basic	$ (2.36)	$ 3.03	$ (9.29)
Earnings (Loss) Per Common Share, from Continuing Operations, Diluted	$ (0.15)	$ 2.70	$ (9.45)
Net Earnings (Loss) Per Common Share, Diluted	$ (2.36)	$ 3.02	$ (9.29)
Dividends Declared Per Common Share	$	$	$ 1.20

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS

(in millions)	Balance at December 31, 2002	2001
ASSETS		
Current Assets		
Cash and cash equivalents	$ 3,895	$ 5,355
Restricted cash	708	195
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $113 million and $89 million, respectively)	2,747	2,750
Regulatory balancing accounts	98	75
Price risk management	498	240
Inventories	347	383
Assets held for sale	707	744
Prepaid expenses and other	480	135
Total current assets	9,480	9,877
Property, Plant and Equipment		
Utility	27,045	25,963
Non-utility:		
Electric generation	636	961
Gas transmission	1,761	1,514
Construction work in progress	1,560	2,383
Other	177	195
Total property, plant and equipment	31,179	31,016
Accumulated depreciation and decommissioning	(14,251)	(13,615)
Net property, plant and equipment	16,928	17,401
Other Noncurrent Assets		
Regulatory assets	2,053	2,319
Nuclear decommissioning funds	1,335	1,337
Price risk management	398	363
Deferred income taxes	657	
Assets held for sale	916	2,254
Other	1,929	2,412
Total other noncurrent assets	7,288	8,685
TOTAL ASSETS	$ 33,696	$ 35,963

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	Balance at December 31,	
	2002	2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Short-term borrowings	$	$ 330
Debt in default	4,230	
Long-term debt, classified as current	298	381
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	1,273	1,020
Regulatory balancing accounts	360	360
Other	660	530
Interest payable	139	26
Income taxes payable	129	610
Price risk management	506	152
Liabilities of operations held for sale	699	570
Other	685	696
Total current liabilities	9,269	4,965
Noncurrent Liabilities		
Long-term debt	4,345	7,222
Rate reduction bonds	1,160	1,450
Deferred income taxes	1,439	1,479
Deferred tax credits	144	153
Price risk management	305	385
Liabilities of operations held for sale	793	1,002
Other	2,963	2,999
Total noncurrent liabilities	11,149	14,690
Liabilities Subject to Compromise		
Financing debt	5,605	5,651
Trade creditors	3,580	5,555
Total liabilities subject to compromise	9,185	11,206
Commitments and Contingencies (Notes 1, 2, 3 and 16)		
Preferred Stock of Subsidiaries	480	480
Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures		300

(in millions, except share amounts)	Balance at December 31,	
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 405,486,015 and 387,898,848 shares, respectively	6,274	5,986
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Accumulated deficit	(1,878)	(1,004)
Accumulated other comprehensive income (loss)	(93)	30
Total common stockholders' equity	3,613	4,322
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 33,696	$ 35,963

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	Year Ended December 31,		
	2002	**2001**	**2000**
Cash Flows from Operating Activities			
Net loss (income)	$ (874)	$ 1,099	$ (3,364)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,309	1,002	3,595
Deferred electric procurement costs			(6,465)
Reversal of ISO accrual	(970)		
Deferred income taxes and tax credits, net	(521)	(535)	(819)
Price risk management assets and liabilities, net	(142)	164	33
Other deferred charges and noncurrent liabilities	263	(744)	256
Provision for loss on generation-related regulatory assets and under-collected purchased power costs			6,939
Loss on impairment or disposal of assets	2,767		
Loss from discontinued operations	1,148		40
Cumulative effect of change in accounting principle	61	(9)	
Net effect of changes in operating assets and liabilities:			
Restricted cash	(513)	(66)	(6)
Accounts receivable	51	1,000	(1,941)
Inventories	36	(75)	68
Accounts payable	377	1,213	4,200
Accrued taxes	(481)	1,851	(1,452)
Regulatory balancing accounts, net	(23)	311	(410)
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromises (Note 2)	(1,442)	(16)	
Assets and liabilities of operations held for sale, net	34	(117)	64
Other working capital	(330)	(399)	331
Other, net	(216)	602	(314)

(in millions)	Year Ended December 31,		
Net cash provided by operating activities	534	5,281	755
Cash Flows from Investing Activities			
Capital expenditures	(3,032)	(2,773)	(2,334)
Net proceeds from sales of businesses			415
Other, net	482	(103)	241
Net cash used by investing activities	(2,550)	(2,876)	(1,678)
Cash Flows from Financing Activities			
Net borrowings (repayments) under credit facilities		(1,148)	2,846
Long-term debt issued	2,414	3,008	1,659
Long-term debt matured, redeemed, or repurchased	(1,644)	(868)	(1,155)
Rate reduction bonds matured	(290)	(290)	
Common stock issued	217	15	65
Common stock repurchased		(1)	(2)
Dividends paid		(109)	(436)
Other, net	(141)	(40)	23
Net cash provided by financing activities	556	567	3,000
Net change in cash and cash equivalents	(1,460)	2,972	2,077
Cash and cash equivalents at January 1	5,355	2,383	306
Cash and cash equivalents at December 31	$ 3,895	$ 5,355	$ 2,383
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 1,414	$ 579	$ 748
Income taxes paid (refunded), net	971	(692)	20
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	419	11,400	

See accompanying Notes to the Consolidated Financial Statements.

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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, 1999	$ 5,906	$ (690)	$ 1,674	$ (4)	$ 6,886	
Net loss			(3,364)		(3,364)	$ (3,364)

(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)
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 and interpretations				(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	
Net loss			(874)		(874)	$ (874)
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133				(139)	(139)	(139)
Net reclassification to earnings				13	13	13
Foreign currency translation adjustment				2	2	2
Other				1	1	1
Comprehensive income						$ (997)
Common stock issued (17,582,636 shares)	217				217	
Other	71				71	
Balance at December 31, 2002	$ 6,274	$ (690)	$ (1,878)	$ (93)	$ 3,613	

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, a Debtor-in-Possession
CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions)	Year Ended December 31,		
	2002	2001	2000
Operating Revenues			
Electric	$ 8,178	$ 7,326	$ 6,854
Natural gas	2,336	3,136	2,783
Total operating revenues	10,514	10,462	9,637
Operating Expenses			
Cost of electricity	1,482	2,774	6,741
Deferred electric procurement cost			(6,465)
Cost of natural gas	954	1,832	1,425
Operating and maintenance	2,817	2,385	2,687
Depreciation, amortization, and decommissioning	1,193	896	3,511
Provision for loss on generation-related regulatory assets and under-collected purchased power costs			6,939
Reorganization professional fees and expenses	155	97	
Total operating expenses	6,601	7,984	14,838
Operating Income (Loss)	3,913	2,478	(5,201)
Reorganization interest income	71	91	
Interest income	3	32	186
Interest expense (non-contractual interest of $149 million for 2002 and $164 million for 2001)	(988)	(974)	(619)
Other income (expense), net	(2)	(16)	(3)
Income (Loss) Before Income Taxes	2,997	1,611	(5,637)
Income tax provision (benefit)	1,178	596	(2,154)
Net Income (Loss)	1,819	1,015	(3,483)
Preferred dividend requirement	25	25	25
Income (Loss) Available for (Allocated to) Common Stock	$ 1,794	$ 990	$ (3,508)

See accompanying Notes to the Consolidated Financial Statements.

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Pacific Gas and Electric Company, a Debtor-in-Possession
CONSOLIDATED BALANCE SHEETS

(in millions) **Balance at December 31,**

(in millions)	Balance at December 31,	
	2002	2001
ASSETS		
Current Assets		
Cash and cash equivalents	$ 3,343	$ 4,341
Restricted cash	150	53
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $59 million and $48 million, respectively)	1,900	2,063
Related parties	17	18
Regulatory balancing accounts	98	75
Inventories:		
Gas stored underground and fuel oil	154	218
Materials and supplies	121	119
Income taxes receivable	50	
Prepaid expenses	110	80
Deferred income taxes	5	
Total current assets	5,948	6,967
Property, Plant and Equipment		
Electric	18,922	18,153
Gas	8,123	7,810
Construction work in progress	427	323
Total property, plant and equipment (at original cost)	27,472	26,286
Accumulated depreciation and decommissioning	(13,515)	(12,929)
Net property, plant and equipment	13,957	13,357
Other Noncurrent Assets		
Regulatory assets	2,011	2,283
Nuclear decommissioning funds	1,335	1,337
Other	1,300	1,325
Total other noncurrent assets	4,646	4,945
TOTAL ASSETS	$ 24,551	$ 25,269

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, a Debtor-in-Possession
CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts) **Balance at December 31,**

(in millions, except share amounts)	Balance at December 31,	
	2002	2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Long-term debt, classified as current	$ 281	$ 333
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	380	333
Related parties	130	86
Regulatory balancing accounts	360	360
Other	374	289
Interest payable	126	26
Income taxes payable		295
Deferred income taxes		65
Other	625	599
Total current liabilities	2,566	2,676
Noncurrent Liabilities		
Long-term debt	2,739	3,019
Rate reduction bonds	1,160	1,450
Regulatory liabilities	1,461	1,485
Deferred income taxes	1,485	1,028
Deferred tax credits	144	153
Other	1,274	1,239
Total noncurrent liabilities	8,263	8,374
Liabilities Subject to Compromise		
Financing debt	5,605	5,651
Trade creditors	3,786	5,733
Total liabilities subject to compromise	9,391	11,384
Commitments and Contingencies (Notes 1, 2, and 16)		
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
Stockholders' Equity		
Preferred stock without mandatory redemption provisions		
Nonredeemable, 5% to 6%, 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 321,314,760 shares	1,606	1,606

(in millions, except share amounts)	Balance at December 31,	
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,964	1,964
Reinvested earnings (accumulated deficit)	805	(989)
Accumulated other comprehensive income (loss)		(2)
Total stockholders' equity	4,194	2,398
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 24,551	$ 25,269

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, a Debtor-in-Possession
CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	Year Ended December 31,		
	2002	**2001**	**2000**
Cash Flows from Operating Activities			
Net income (loss)	$ 1,819	$ 1,015	$ (3,483)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred electric procurement costs			(6,465)
Depreciation, amortization, and decommissioning	1,193	896	3,511
Deferred income taxes and tax credits, net	378	(306)	(930)
Other deferred charges and noncurrent liabilities	102	(954)	480
Reversal of ISO accrual (Note 2)	(970)		
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:			
Restricted cash	(97)	(3)	(8)
Accounts receivable	212	105	(507)
Income tax receivable	(50)	1,120	(1,120)
Inventories	62	(57)	14
Accounts payable	198	1,312	3,063
Income taxes payable	(295)	295	(118)
Regulatory balancing accounts, net	(23)	311	(410)
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise (Note 2)	(1,442)	(16)	
Other working capital	11	711	111
Other, net	36	336	(522)
Net cash provided by operating activities	1,134	4,765	555

(in millions)	Year Ended December 31,		
Cash Flows from Investing Activities			
Capital expenditures	(1,546)	(1,343)	(1,245)
Proceeds from sale of assets	11		6
Other, net	26	5	32
Net cash used by investing activities	(1,509)	(1,338)	(1,207)
Cash Flows from Financing Activities			
Net (repayments) borrowings under credit facilities and short-term borrowings		(28)	2,630
Long-term debt issued			680
Long-term debt matured, redeemed, or repurchased	(333)	(111)	(307)
Rate reduction bonds matured	(290)	(290)	(290)
Common stock repurchased			(275)
Dividends paid			(475)
Other, net		(1)	(26)
Net cash provided (used) by financing activities	(623)	(430)	1,937
Net change in cash and cash equivalents	(998)	2,997	1,285
Cash and cash equivalents at January 1	4,341	1,344	59
Cash and cash equivalents at December 31	$ 3,343	$ 4,341	$ 1,344
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	$ 75	$ 87	$
Cash paid for:			
Interest (net of amounts capitalized)	1,105	361	587
Income taxes (net of refunds)	1,186	(556)	
Reorganization professional fees and expenses	99	19	
Supplemental disclosures of noncash investing and financing activities			
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities, net	419	11,400	

See accompanying Notes to the Consolidated Financial Statements.

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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	Total Common Stockholders' Equity	Preferred Stock Without Mandatory Redemption Provisions	Comprehensive Income (Loss)

					(Loss)			
Balance 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 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					(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 December 31, 2001	1,606	1,964	(475)	(989)	(2)	2,104	294	
Net Income				1,819		1,819		$ 1,819
Foreign currency translation adjustments					2	2		2
Comprehensive income								$ 1,821
Preferred stock dividend				(25)		(25)		
Balance December 31, 2002	$ 1,606	$ 1,964	$ (475)	$ 805	$	$ 3,900	$ 294	

See accompanying Notes to the Consolidated Financial Statements.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: GENERAL

Organization and Basis of Presentation

PG&E Corporation, incorporated in California in 1995, is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation conducts its business through various subsidiaries, principally Pacific Gas and Electric Company (the Utility), an operating regulated electric and natural gas distribution and transmission utility company, and PG&E National Energy Group, Inc. (PG&E NEG), a power generation, wholesale energy marketing and trading, risk management, and natural gas transmission company.

The Consolidated Financial Statements of PG&E Corporation and of the Utility have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets and repayment of liabilities in the ordinary course of business. However, as a result of the bankruptcy of the Utility and current liquidity concerns at PG&E NEG and its subsidiaries, as further discussed below, such realization of assets and liquidation of liabilities are subject to uncertainty.

Consolidation Policy

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 (GAAP) requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of revenues, expenses, assets, and liabilities and the disclosure of contingencies. As these estimates involve judgments on a wide range of factors, including future economic conditions, that are difficult to predict, actual results could differ significantly 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).

Nature of Operations

The Utility, incorporated in California in 1905, provides electric service to approximately 4.8 million customers and natural gas service to approximately 4.0 million customers in Northern and Central California. Effective January 1, 1997, PG&E Corporation became the holding company of the Utility and its subsidiaries. The Utility is the predecessor of PG&E Corporation.

PG&E NEG, 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 main subsidiaries of PG&E NEG include the following:

- 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, including North Baja Pipeline, LLC (NBP) (collectively, PG&E GTN).

PG&E NEG also has other less significant subsidiaries.

PG&E National Energy Group, LLC owns 100 percent of the stock of PG&E NEG, GTN Holdings LLC owns 100 percent of the stock of PG&E GTN, and PG&E Energy Trading Holdings LLC owns 100 percent of the stock of PG&E ET. The organizational documents of PG&E NEG and these limited liability companies require unanimous approval of their respective boards of directors, including at least one independent director, before they can:

- Consolidate or merge with any entity;
- Transfer substantially all of their assets to any entity; or
- Institute or consent to bankruptcy, insolvency or similar proceedings or actions.

The limited liability 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.

Bankruptcy of the Utility

As discussed further in Note 2, 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 continues to control its assets and is allowed to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court.

Due to the Utility's Chapter 11 filing, the financial statements for both PG&E Corporation and the Utility are prepared in accordance with the American Institute of Certified Public Accountants' Statement of Position (SOP) 90-7, which is applied by reorganizing entities operating under the bankruptcy code. Under SOP 90-7, certain liabilities of the Utility existing prior to its bankruptcy filing are classified as Liabilities Subject to Compromise. Additionally, professional fees and expenses directly related to the Chapter 11 proceeding and interest income on funds accumulated during the bankruptcy are reported separately as reorganization items. Finally, the extent to which the Utility's reported interest expense differs from its stated contractual interest is disclosed on the Consolidated Statements of Operations.

PG&E NEG

The Consolidated Financial Statements have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets and repayment of liabilities in the ordinary course of business. However, as a result of current liquidity concerns at PG&E NEG and its subsidiaries and restructuring discussions with their lenders, such realization of assets and liquidation of liabilities are subject to uncertainty.

As a result of the sustained downturn in the power industry, PG&E NEG and its affiliates have experienced a financial downturn which caused the major credit rating agencies to downgrade PG&E NEG's and its affiliates' credit ratings to below investment-grade. PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements

totaling $2.5 billion, but this debt is non-recourse to PG&E NEG. PG&E NEG, its subsidiaries and their lenders are engaged in discussions to restructure PG&E NEG's and its subsidiaries debt obligations and other commitments. PG&E NEG and certain subsidiaries have significantly reduced their energy trading operations. These asset transfers, sales, and abandonments have caused substantial charges to earnings in 2002 of approximately $3.9 billion. PG&E NEG and its subsidiaries are continuing these efforts to abandon, sell or transfer additional assets in an ongoing effort to raise cash, reduce debt, whether through negotiation with lenders or otherwise. As a result, PG&E expects to incur additional substantial charges in 2003 as it restructures operations. If a restructuring agreement is not reached and the lenders exercise their default remedies or if the financial obligations and commitments are not restructured, PG&E NEG and certain of its subsidiaries may be compelled to seek protection under or be forced involuntarily into proceedings under the Bankruptcy Code.

Earnings (Loss) Per Share

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per share is calculated by dividing net income (loss), adjusted for convertible note interest and amortization, by the weighted average number of common shares outstanding plus the assumed issuance of common shares for all dilutive securities.

The following table details 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,**		
	2002	**2001**	**2000**

(in millions, except per share amounts)	Year ended December 31,		
Income (loss) from continuing operations	$ (57)	$ 983	$ (3,423)
Discontinued operations	(756)	107	59
Net income (loss) before cumulative effect of accounting change	(813)	1,090	(3,364)
Cumulative effect of accounting change	(61)	9	
Net Income (loss)	$ (874)	$ 1,099	$ (3,364)
Weighted average common shares outstanding, basic	371	363	362
Add: Employee Stock Options and PG&E Corporation shares held by grantor trusts		1	
Shares outstanding for diluted calculations	371	364	362
Earnings (Loss) Per Common Share, Basic			
Income (loss) from continuing operations	$ (0.15)	$ 2.71	$ (9.45)
Discontinued operations	(2.04)	0.29	0.16
Cumulative effect of change in accounting principle	(0.17)	0.02	
Rounding		0.01	
Net earnings (loss)	$ (2.36)	$ 3.03	$ (9.29)
Earnings (Loss) Per Common Share, Diluted			
Income (loss) from continuing operations	$ (0.15)	$ 2.70	$ (9.45)
Discontinued operations	(2.04)	0.29	0.16
Cumulative effect of change in accounting principle	(0.17)	0.02	
Rounding		0.01	
Net earnings (loss)	$ (2.36)	$ 3.02	$ (9.29)

The diluted earnings per share for the year ended December 31, 2002, excludes approximately two million incremental shares related to employee stock options and shares held by grantor trusts, two million incremental shares related to warrants, and ten million incremental shares related to the 9.5 percent Convertible Subordinated Notes and includes associated interest expense of $8 million (net of income tax of $5 million) due to the antidilutive effect upon loss from continuing operations. In

addition, the diluted share base for the year ended December 31, 2000, excludes two million incremental shares related to employee stock options and shares held by grantor trusts to secure deferred compensation obligations due to the antidilutive effect upon loss from continuing operations.

PG&E Corporation reflects the preferred dividends of subsidiaries as other expense which is used to calculate both basic and diluted earnings per share.

Summary of Significant Accounting Policies

Adoption of New Accounting Policies

Consolidation of Variable Interest Entities In January 2003 the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46), which expands upon existing accounting guidance addressing when a company should include in its financial statements the assets, liabilities, and activities of another entity. FIN 46 notes that many of what are now referred to as "variable interest entities" have commonly been referred to as special-purpose entities or off-balance sheet structures. However, the Interpretation's guidance is to be applied to not only these entities but to all entities found within a company. FIN 46 provides some general guidance as to the definition of a variable interest entity. PG&E Corporation is currently evaluating all entities to determine if they meet the FIN 46 criteria as variable interest entities.

Until the issuance of FIN 46, one company generally included another entity in its Consolidated Financial Statements only if it controlled the entity through voting interests. FIN 46 changes that by requiring a variable interest entity to be consolidated by a company if that company is subject to a majority of the risk of loss from the variable interest entity's activities or entitled to receive a majority of the entity's residual returns, or both. A company that consolidates a variable interest entity is now referred to as the "primary beneficiary" of that entity.

FIN 46 requires disclosure of variable interest entities that the company is not required to consolidate but in which it has a significant variable interest.

The consolidation requirements of FIN 46 apply immediately to variable interest entities created after January 31, 2003. The consolidation requirements apply to variable interest entities created before January 31, 2003, in the first fiscal year or interim period beginning after June 15, 2003, so these requirements would be applicable to PG&E Corporation in the third quarter 2003. Certain new and expanded disclosure requirements apply to all financial statements issued after January 31, 2003, regardless of when the variable interest entity was established. These disclosures are required if there is an assessment that it is reasonably possible that an enterprise will consolidate or disclose information about a variable interest entity when FIN 46 becomes effective. PG&E Corporation is currently evaluating the impacts of FIN 46's initial recognition, measurement, and disclosure provisions on its Consolidated Financial Statements.

Guarantor's Accounting and Disclosure Requirements for Guarantees In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 expands on the accounting guidance of Statement of Financial Accounting Standards (SFAS) No. 5, "Accounting for Contingencies," SFAS No. 57, "Related Party Disclosures," and SFAS No. 107, "Disclosures about Fair Value of Financial Instruments." FIN 45 also incorporates, without change, the provisions of FASB Interpretation No. 34, "Disclosures of Indirect Guarantees of the Indebtedness of Others," which it supersedes.

FIN 45 elaborates on the existing disclosure requirements for most guarantees. It clarifies that a guarantor's required disclosures include the nature of the guarantee, the maximum potential undiscounted payments that could be required, the current carrying amount of the liability, if any, for the guarantor's obligations (including the liability recognized under SFAS No. 5), and the nature of any recourse provisions or available collateral that would enable the guarantor to recover amounts paid under the guarantee.

FIN 45 also clarifies that at the time a company issues a guarantee, it must recognize an initial liability for the fair value of the obligation it assumes under that guarantee, including its ongoing obligation to stand ready to perform over the term of the guarantee in the event that specified

triggering events or conditions occur. This information must also be disclosed in interim and annual financial statements.

FIN 45 does not prescribe a specific account for the guarantor's offsetting entry when it recognizes the liability at the inception of the guarantee, noting that the offsetting entry would depend on the circumstances in which the guarantee was issued. There also is no prescribed approach included for subsequently measuring the guarantor's recognized liability over the term of the related guarantee. It is noted that the liability would typically be reduced by a credit to earnings as the guarantor is released from risk under the guarantee.

The initial recognition and initial measurement provisions apply on a prospective basis to guarantees issued or modified after December 31, 2002. PG&E Corporation is currently evaluating the impact of FIN 45's initial recognition and measurement provisions on its Consolidated Financial Statements. The disclosure requirements for FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002, and have been incorporated into PG&E Corporation's December 31, 2002, disclosures of guarantees in these footnotes.

Accounting for Stock-Based Compensation Transition and Disclosures On December 31, 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation Transition and Disclosures, an Amendment of FASB Statement No. 123." This Statement provides alternative methods of transition for companies who voluntarily change to the fair value-based method of accounting for stock-based employee compensation in accordance to SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 148 does not permit the use of the original SFAS No. 123 prospective method of transition for changes to the fair value based method made in fiscal years beginning after December 15, 2003. The Statement also requires prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used on reported results. This Statement is effective upon its issuance.

PG&E Corporation continues to account for stock-based compensation using the intrinsic value method in accordance with the provisions of Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees," elected under SFAS No. 123, as amended. As a result, the adoption of this Statement did not have any impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

Please refer to the Stock-Based Compensation section of this Note 1 for additional information.

Change from Gross to Net Method of Reporting Revenues and Expenses on Trading Activities Effective for the quarter ended September 30, 2002, PG&E Corporation changed its method of reporting gains and losses associated with energy trading contracts from the gross method of presentation to the net method. PG&E Corporation believes that the net method provides a more accurate and consistent presentation of energy trading activities on the financial statements. Amounts to be presented under the net method include all gross margin elements related to energy trading activities, including both unrealized and realized trades and both physical and financial trades.

Before implementation of the net method, PG&E Corporation already had reported unrealized gains and losses on trading activities on a net basis in operating revenues. However, PG&E Corporation had reported realized gains and losses on a gross basis in operating income, as both operating revenues and costs of commodity sales and fuel. PG&E Corporation is now reporting all gains and losses from trading activities, including amounts that are realized, on a net basis as operating revenues. This will provide greater consistency in reporting the results of all energy trading activities. All prior year financial statements have been reclassified to conform to the net method.

Implementation of the net method has no net effect on gross margin, operating income, or net income. Accordingly, PG&E Corporation continues to report realized income from non-trading activities on a gross basis in operating revenues and operating expenses. The schedule below

summarizes the amounts impacted by the change in methodology on PG&E Corporation's Consolidated Statements of Operations for the years ended December 31, 2001 and 2000.

(in millions)	**Prior Method of Presentation (Gross Method)**		**As Presented (Net Method)**	
	2001	**2000**	**2001**	**2000**
Energy commodities and services(1)	$ 11,647	$ 15,809	$ 1,841	$ 3,062
Cost of energy commodities and services(2)	11,026	14,933	1,220	2,186
Net subtotal	$ 621	$ 876	$ 621	$ 876

(1) These amounts, as presented in the net method, differ from the financial statements due to the exclusion of equity earnings in affiliates, and eliminations and other, which amounted to net charges of $93 million and $131 million at December 31, 2001, and 2000, respectively.

(2) These amounts, as presented in the net method, differ from the financial statements due to the exclusion of eliminations and other, which amounted to net charges of $172 million and $196 million at December 31, 2001, and 2000, respectively.

Rescission of EITF 98 - 10 In October 2002, the Emerging Issues Task Force (EITF) rescinded EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." Energy trading contracts that are derivatives in accordance with 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), will continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked to market as trading activities under EITF 98-10 that do not meet the definition of a derivative will be recorded at cost, with a one-time adjustment to be recorded as a cumulative effect of a change in accounting principle as of January 1, 2003. For PG&E Corporation, the majority of trading contracts are derivative instruments as defined in SFAS No. 133. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading purposes, which continue to be accounted for in accordance with SFAS No. 133.

The reporting requirements associated with the rescission of EITF 98-10 are to be applied prospectively for all EITF 98-10 energy trading contracts entered into after October 25, 2002. For all EITF 98-10 energy trading contracts in existence at or prior to October 25, 2002, the estimated impact of the first quarter 2003 cumulative effect of a change in accounting principle is a loss of $5 million, net of taxes at December 31, 2002.

Change in Estimate Due to Changes in Certain Fair Value Assumptions PG&E Corporation estimates the gross mark-to-market value of its trading contracts and certain non-trading contracts using forward curves. The forward curves used to calculate mark-to-market value have liquid periods (includes continuous maturities starting from the month for which broker quotes are available on a daily basis) and illiquid periods (includes those maturities for which broker quotes are not readily available). When market data is not available, PG&E Corporation historically has utilized alternative pricing methodologies, including third-party pricing curves, the extrapolation of forward pricing curves using historically reported data, and interpolation between existing data points. The gross mark-to-market valuation is then adjusted for time value of money, creditworthiness of contractual counterparties, market liquidity in future periods, and other adjustments necessary to determine fair value. For trading activities, these models are used to estimate the fair value of long-term transactions including certain tolling agreements. For non-trading activities, these models are used to estimate the fair value of certain derivative contracts accounted for as cash flow hedges or at fair value through earnings under SFAS No. 133.

Beginning in the third quarter of 2002, PG&E Corporation implemented a new model for projecting forward power and gas prices during illiquid periods. This new process primarily impacts the estimation of power prices. The model estimates forward power prices in illiquid periods using the mid-point of the marginal cost curve (the lowest variable cost of generation available in a particular region) and the forecast curve (the price at which a generation unit will recover its capital costs and a return on investment). Assumptions about cost recovery are combined with assumptions about volatility and correlation in an option model to project forward power prices. Interpolation methods continue to be used for intermediate periods when broker quotes are intermittent. In addition to implementing the new process for projecting forward power prices in illiquid periods, PG&E Corporation also enhanced its models to better incorporate certain physical characteristics of its power plants, and to account for uncertainties surrounding projected forward prices, volumetric assumptions, and modeling complexity. PG&E Corporation also refined its process for estimating the bid-ask spread in illiquid periods for purposes of liquidity adjustments.

All of these changes in fair values are being accounted for on a prospective basis as a change in accounting estimate. The change in fair values had a pre-tax income effect of a $14 million loss from trading activities and a pre-tax gain of $25 million from non-trading activities. These income effects, totaling a pre-tax gain of $11 million for both trading and non-trading activities, were recognized in the quarter ended September 30, 2002.

Accounting for Gains and Losses on Debt Extinguishment and Certain Lease Modifications On July 1, 2002, PG&E Corporation adopted SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." This Statement eliminates the current requirement that gains and losses on debt extinguishment be classified as extraordinary items. Instead, such gains and losses will generally be classified as interest expense. During 2002, PG&E Corporation recorded $115 million of debt extinguishment losses as a charge to interest expense relating to note prepayments and ratings waiver extensions.

In addition, SFAS No. 145 eliminates an inconsistency in lease accounting by requiring that modifications of capital leases that result in reclassification as operating leases be accounted for consistently with sale-leaseback accounting rules. This provision did not have any impact on the Consolidated Financial Statements of PG&E Corporation or the Utility at the date of adoption.

Changes to Accounting for Certain Derivative Contracts On April 1, 2002, PG&E Corporation implemented two interpretations issued by the FASB's Derivatives Implementation Group (DIG). DIG Issues C15 and C16 changed the definition of normal purchases and sales included in SFAS No. 133. Previously, certain derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business were exempt from the requirements of SFAS No. 133 under the normal purchases and sales exception, and thus were not marked to market and reflected on the balance sheet like other derivatives. Instead, these contracts were recorded on an accrual basis.

DIG C15 changed the definition of normal purchases and sales for certain power contracts. DIG C16 disallowed normal purchases and sales treatment for commodity contracts (other than power contracts) that contain volumetric variability or optionality. PG&E NEG determined that five of its derivative commodity contracts for the physical delivery of power and purchase of fuel no longer qualified for normal purchases and sales treatment under these interpretations. Beginning April 1, 2002, these five contracts were required to be recorded on the balance sheet at fair value and marked to market through earnings. Three of the contracts had positive market values and resulted in pre-tax income of $125 million. The remaining two contracts had negative market values that resulted in a pre-tax charge of $127 million. The cumulative effects of implementing these accounting changes at April 1, 2002, resulted in PG&E Corporation recording price risk management assets of $37 million,

price risk management liabilities of $255 million, and a reduction of out-of-market obligations of $129 million reclassified to net price risk management liabilities.

One of the contracts with a positive market value included above is a power sales contract at a partnership in which PG&E NEG has a 50 percent ownership interest. PG&E NEG reflects its investment in this partnership on an equity basis (Investments in Unconsolidated Affiliates). Upon adoption of DIG C15 and C16, PG&E NEG recognized its equity share of the gain from the cumulative change in accounting method and correspondingly increased the book value of its equity investment in the partnership. However, the future net cash flows from the partnership do not support the increased equity investment balance. Therefore, PG&E NEG has recognized an impairment charge of $101 million to reduce its equity-method investment to fair value.

The cumulative effect of the change in accounting principle for DIG C15 and C16 was a net charge of $61 million, after-tax, and included the recognition of the fair market value of the five contracts impacted by DIG C15 and C16 and the impairment charge for the equity method investment. The Utility was not impacted by these accounting changes.

Implementation of these accounting changes will not impact the timing and amount of cash flows associated with the affected contracts; however, it will impact the timing and magnitude of future earnings. Future earnings will reflect the gradual reversal of the assets and liabilities recorded upon adoption over the contracts' lives, as well as any prospective changes in the market value of the contracts. Prospective changes in the market value of these contracts could result in significant volatility in earnings. However, over the total lives of the contracts, there will be no net impact to total operating results after netting the cumulative effect of adoption against the subsequent years' impacts (assuming that the affected contracts are held to their expiration).

Accounting for the Impairment or Disposal of Long-Lived Assets On January 1, 2002, PG&E Corporation adopted SFAS No. 144, "Accounting 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 its fundamental provision for recognizing and measuring impairment of long-lived assets to be held and used. This Statement requires that all long-lived assets to be disposed of by sale be carried at the lower of carrying amount or fair value less cost to sell, and that depreciation cease to be recorded on such assets. SFAS No. 144 standardizes the accounting and presentation requirements for all long-lived assets to be disposed of by sale, and supersedes previous guidance for discontinued operations of business segments. The initial adoption of this Statement at January 1, 2002, did not have any impact on the Consolidated Financial Statements of PG&E NEG. During 2002, PG&E NEG recorded certain impairment charges in accordance with SFAS No. 144 (see Note 6, "Discontinued Operations" and Note 7, "Impairments, Write-offs, and Other Charges").

Accounting for Goodwill and Other Intangible Assets On January 1, 2002, PG&E Corporation adopted 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. Upon implementation of this Statement, the transition impairment test for goodwill was performed as of January 1, 2002, and no impairment loss was recorded. Goodwill amortization expense was $5 million in 2001 and 2000. During 2002, PG&E NEG recorded a charge for impairment of goodwill in accordance with SFAS No. 142 (see Note 7, Impairment, Write-offs, and Other Charges). The Utility had no goodwill on its balance sheet at December 31, 2002, or December 31, 2001.

This Statement also requires that the useful lives of previously recognized intangible assets be reassessed and the remaining amortization periods be adjusted accordingly. Adoption of this Statement did not require any adjustments to be made to the useful lives of existing intangible assets and no reclassifications of intangible assets to goodwill were necessary.

Intangible assets other than goodwill are being amortized on a straight-line basis over their estimated useful lives, and are reported under non-current assets in the Consolidated Balance Sheets.

The schedule below summarizes the amount of intangible assets by major classes:

(in millions)	Balance at December 31,			
	2002		2001	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
PG&E NEG:				
Service agreements	$ 33	$ 7	$ 33	$ 6
Power sale agreements	14	9	25	8
Other agreements	12	6	17	5
Utility:				
Hydro licenses and other agreements	67	16	66	14
PG&E Corporation Consolidated	$ 126	$ 38	$ 141	$ 33

PG&E NEG's amortization expense on intangible assets was $7 million in 2002, $3 million in 2001, and $4 million in 2000. The Utility's amortization expense of intangible assets was $3 million in 2002, $2 million in 2001, and $2 million in 2000.

The following schedule shows the estimated amortization expenses for intangible assets for full years 2003 through 2007.

(in millions)	2003	2004	2005	2006	2007
PG&E NEG	$ 4	$ 3	$ 3	$ 3	$ 3
Utility	$ 3	$ 3	$ 3	$ 3	$ 3

Accounting for Asset Retirement Obligations In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." PG&E Corporation and the Utility will adopt this Statement effective January 1, 2003. SFAS No. 143 provides accounting requirements for costs associated with legal obligations to retire tangible, long-lived assets. 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. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the related asset. Upon adoption, the cumulative effect of applying this Statement will be recognized as a change in accounting principle in the Consolidated Statements of Operations. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this statement and costs recovered through the ratemaking process. Regulatory assets and liabilities may be recorded when it is probable that the asset retirement costs will be recovered through the ratemaking process.

PG&E Corporation estimates the impact of adopting SFAS No. 143 effective January 1, 2003, will be as follows:

The Utility will adjust its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. The Utility will also recognize asset retirement obligations associated with the decommissioning of other fossil generation assets.

At December 31, 2002, the total nuclear decommissioning obligation accrued was $1.3 billion and is included in accumulated depreciation and decommissioning on the Consolidated Balance Sheets (see Note 13, "Nuclear Decommissioning"). The Utility has accrued, at December 31, 2002, $52 million to decommission certain fossil generation assets based on its estimate of the decommissioning obligation under the accounting principles in effect at that time. These decommissioning obligations are also included in accumulated depreciation and decommissioning on the Consolidated Balance Sheets.

The Utility estimates it will recognize an adjustment to its recorded nuclear and fossil facility decommissioning obligations in the range of an increase of $222 million to a decrease of $192 million for asset retirement obligations in existence as of January 1, 2003. The estimated cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation and decommissioning expense accrued to date will range from a loss of $19 million to a gain of $17 million (pre-tax).

PG&E NEG estimates that it will recognize a liability in the range of $11 million to $21 million for asset retirement obligations on January 1, 2003. The cumulative effect of a change in accounting principle from unrecognized accretion and depreciation expense is estimated to be a loss in the range of $4 million to $6 million (pre-tax). The impact to PG&E NEG of implementing SFAS No. 143 by its unconsolidated affiliates is expected to be immaterial.

Cash and Cash Equivalents

Invested cash and other investments with original maturities of three months or less are considered cash equivalents. Cash equivalents are stated at cost, which approximates fair value. PG&E Corporation's and the Utility's cash equivalents are held in a variety of funds that mainly invest in:

- Certificates of deposit and 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, 2002, have matured and have been reinvested.

At December 31, 2002, two 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 and the Fiduciary Trust Company International.

Restricted Cash

Restricted cash includes cash and cash equivalents, as defined above, which are (1) restricted under the terms of certain agreements for payment to third parties, and (2) held in escrow as collateral required by the California Independent System Operator (ISO) and other counterparties.

Inventories

Inventories include materials and supplies, gas stored underground, coal, and fuel oil. Materials, supplies, and gas stored underground are valued at average cost. Coal and fuel oil are valued using the last-in first-out method. PG&E ET's natural gas inventory is valued at cost as discussed in Note 1, Recission of EITF 98-10.

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 where applicable. PG&E Corporation and the Utility are parties to a tax-sharing arrangement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

PG&E NEG is included in the consolidated tax return of PG&E Corporation. Certain creditors of PG&E NEG have asserted that past payments from tax benefits gave rise to an implied tax sharing agreement between PG&E Corporation and PG&E NEG. PG&E Corporation disputes this assertion.

Property, Plant and Equipment

Property, Plant and Equipment are reported at its original cost, unless impaired under the provisions of SAFS No. 144. Original costs include:

- Labor and 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 that is allowed to be recorded as part of the costs of construction projects. AFUDC is recoverable from customers through rates once the property is placed in service.

Capitalized Interest and AFUDC

(in millions)	**Year ended December 31,**		
	2002	**2001**	**2000**
PG&E Corporation	$ 42	$ 22	$ 19
Utility	27	18	18

PG&E Corporation and the Utility periodically evaluate long-lived assets, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of these assets may be impaired.

PG&E Corporation charged the original cost of retired plant and removal costs less salvage value to accumulated depreciation upon retirement of plant in service for the Utility and for PG&E NEG's lines of business that apply 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 from related accounts are included in the amounts in the determination of the gain or loss on disposition.

Depreciation

Property, plant and equipment are depreciated on a straight-line basis over estimated useful lives, less any residual or salvage value.

Composite depreciation rates	**Year ended December 31,**		
	2002	**2001**	**2000**
PG&E Corporation	3.36%	3.07%	4.49%
Utility	3.42%	3.63%	4.54%

Estimated useful lives	**Utility**	**PG&E NEG**
Electric generating facilities	15 to 50 years	20 to 50 years
Electric distribution facilities	16 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 40 years	2 to 20 years

The useful lives of the Utility's property, plant and equipment are authorized by the CPUC. Depreciation rates include a component for the cost of asset retirement net of salvage value. The Utility has a separate rate component for the accrual of its recorded obligation for nuclear decommissioning which is included in depreciation, amortization, and decommissioning expense in the accompanying Consolidated Statements of Operations. The accrued net asset retirement obligation is included in accumulated depreciation and decommissioning in the accompanying Consolidated Balance Sheets.

Refer to the section "Accounting for the Impairment or Disposal of Long-Lived Assets" in this Note and Note 7 "Impairment, Write-offs, and Other Charges" for a discussion of impairment and the effect on Property, Plant and Equipment.

Nuclear Fuel

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

Capitalized Software Costs

PG&E Corporation capitalizes costs incurred during the application development stage of internal use software projects to property, plant and equipment. Capitalized software costs totaled $349 million at December 31, 2002, and $269 million at December 31, 2001, net of accumulated amortization of $154 million at December 31, 2002, and $112 million at December 31, 2001. PG&E Corporation amortizes capitalized software costs ratably over the expected lives of the projects ranging from 3 to 15 years, commencing operational use, in accordance with regulatory requirements.

Gains and Losses on Debt Extinguishments

Gains and losses on debt extinguishments associated with regulated operations that are subject to the provisions of SFAS No. 71 are deferred and amortized over the remaining original amortization period of the debt reacquired, consistent with ratemaking principles. Gains and losses on debt extinguishments associated with unregulated operations are recognized at the time such debt is reacquired, and upon adoption of SFAS No. 145 on July 1, 2002 are reported as interest expense unless they were determined to be unusual and infrequent, in which case they would be reported as extraordinary gains or losses.

Fair Value of Financial Instruments

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

PG&E Corporation 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, debt in default, and accounts payable, approximate their carrying values as of December 31, 2002, and 2001;

The fair value of the Utility's debt, for which no market quotations are readily available, is obtained from third-party experts with extensive experience in the fair valuation of such instruments. The fair value of a small portion of the Utility's debt is determined using the present value of future cash flows; and

The fair values of nuclear decommissioning funds, rate reduction bonds, the Utility's preferred stock, and the Utility's 7.90 percent deferrable interest subordinated debentures are determined based on quoted market prices.

Due to the illiquid nature and limited demand for PG&E NEG's long-term debt, the estimated fair value at December 31, 2002, was not able to be determined. At December 31, 2001, PG&E NEG's long-term receivables had a carrying value of $536 million and estimated fair value of $467 million. At December 31, 2001, PG&E NEG's long-term debt had a carrying value of $3.4 billion and an estimated fair value of $3.5 billion.

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

(in millions)	**At December 31,**			
	2002		**2001**	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Nuclear decommissioning funds (Note 13):				
Utility	$ 1,335	$ 1,335	$ 1,337	$ 1,337
Long-term debt (Note 4):				
PG&E Corporation	1,000	1,000	1,000	1,000
Utility	4,820	4,631	5,153	4,975
Rate reduction bonds (Note 5):				
Utility	1,450	1,580	1,740	1,811
Utility preferred stock with mandatory redemption provisions (Note 10):	137	132	137	109
7.90 Percent cumulative quarterly income preferred securities (Note 4)			300	246
7.90 Percent deferrable interest subordinated debentures (Note 4)	300	275		

Regulation and Statement of Financial Accounting Standards No. 71

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

If portions of the Utility's or PG&E GTN's 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.

Regulatory Assets

Regulatory assets comprise the following:

(in millions)	Balance at December 31,	
	2002	2001
Rate reduction bond assets	$ 1,346	$ 1,636
Unamortized loss, net of gain, on reacquired debt	299	322
Regulatory assets for deferred income tax	229	188
Other, net	137	137
Total Utility regulatory assets	2,011	2,283
PG&E GTN	42	36
Total PG&E Corporation regulatory assets	$ 2,053	$ 2,319

Regulatory assets are charged to expense during the period that the costs are reflected in regulated revenues.

The Utility's regulatory asset related to rate reduction bonds is 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 over the remaining original amortization period of the reacquired debt over periods ranging from 1 to 24 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, 2002, the Utility did not earn a return on regulatory assets related to deferred income taxes of $229 million.

Regulatory Liabilities

Regulatory Liabilities comprise the following:

(in millions)	Balance at December 31,	
	2002	2001
Employee benefit plans	$ 1,102	$ 1,133
Public purpose programs	182	218
Rate reduction bonds	102	17
Other	75	117
Total Utility regulatory liabilities	1,461	1,485
PG&E GTN	14	12

(in millions)	Balance at December 31,	
Total PG&E Corporation regulatory liabilities	$ 1,475	$ 1,497

The Utility's regulatory liabilities related to employee benefit plan expenses represent the cumulative differences between expenses recognized for financial accounting purposes and expenses recognized for ratemaking purposes. These balances will be charged against expense to the extent that future financial accounting expenses exceed amounts recoverable for regulatory purposes. The Utility's regulatory liabilities related to public purpose programs represent revenues designated for public purpose program costs that are expected to be incurred in the future. The Utility's regulatory liability for rate reduction bonds represents the deferral of over-collected revenue associated with the rate reduction bonds that the Utility expects to return to ratepayers in the future.

Regulatory Balancing Accounts

Sales balancing accounts accumulate differences between recorded revenues and revenues the Utility is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs the Utility is authorized to recover through rates. Under-collections that are probable of recovery 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 2, the Utility could no longer conclude that power-generation and procurement-related balancing accounts meet the requirements of SFAS No. 71. However, the Utility continues to record balancing accounts associated with its electricity and gas distribution and transmission businesses.

In 2002, the CPUC ordered the Utility to create certain electric balancing accounts to track specific electric-related costs but has not yet determined the recovery method for these costs. In the decisions ordering the creation of these balancing accounts, the CPUC indicated that the recovery method of these amounts would be determined in the future. Because the Utility cannot conclude that the amounts in these balancing accounts are considered probable of recovery in future rates, the Utility has reserved these balances by recording a charge against earnings. As of December 31, 2002, the reserve for these balances was $136 million.

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

(in millions)	Balance at December 31,	
	2002	**2001**
Gas Revenue Balancing Accounts	$ 65	$ 42
Gas Cost Balancing Accounts	33	25
Electric Distribution Cost Balancing Accounts		8
Total	$ 98	$ 75

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

(in millions)	Balance at December 31,	
	2002	**2001**
Gas Revenue Balancing Accounts	$ 4	$ 31

(in millions)	Balance at December 31,			
Gas Cost Balancing Accounts		226		178
Electric Transmission and Distribution Revenue Balancing Accounts		98		151
Electric Transmission Cost Balancing Accounts		32		
Total	$	360	$	360

The Utility expects to collect from or refund to its ratepayers the balances included in current balancing accounts receivable and payable within the next twelve months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next twelve months are included in non-current regulatory assets and liabilities.

Revenue Recognition

Revenues are recorded in accordance with the Securities and Exchange Commission (SEC) 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. 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. Gas utility revenues, which are comprised of transmission and distribution services, are also billed at CPUC-approved rates. 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.

As discussed in Note 2, since January 2001, the California Department of Water Resources (DWR) has purchased electricity on behalf of the Utility's customers to cover the amount of electricity needed by the Utility's customers that could not be met by the Utility's purchased power contracts and retained generation facilities. Under California law, the DWR is deemed to sell the electricity directly to the Utility's retail customers, not to the Utility. Therefore, the Utility is a pass-through entity for transactions between its customers and the DWR. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts from electric

revenues amounts passed through to the DWR. The pass-through amounts are based on the DWR's CPUC-approved revenue requirement and are excluded from the Utility's electric revenues in its Consolidated Statements of Operations.

In accordance with EITF 98-10 and SFAS No. 133, certain energy trading contracts that are not designated as hedging instruments or as normal purchase and sale contracts, are recorded at fair value using mark-to-market accounting, which records a change in fair value as income (or a charge) on the income statement, and correspondingly adjusts the fair value of the instrument on the balance sheet. Effective January 1, 2003, all non-derivative energy trading contracts that were marked to market under EITF 98-10 will be accounted for using the cost method. Please refer to the Adoption of New Accounting Policies section of this note for additional information.

Revenues from trading activities are reported on a net basis in operating revenues for both realized and unrealized gains (and losses). Realized revenues and costs of sales from non-trading activities are reported on a gross basis as operating revenues and operating expenses, respectively.

Accounting for Price Risk Management Activities

PG&E Corporation, primarily through its subsidiaries, engages in price risk management activities for both non-trading and trading purposes. 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. Because of the Utility's credit rating downgrade and subsequent bankruptcy, risk management activities have been limited to forward and option contracts related to the Utility's natural gas portfolio and the continuation of power forward contracts that were in existence prior to the bankruptcy.

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.

PG&E NEG is significantly reducing their energy trading operations.

Derivatives associated with both non-trading and trading activities include forward contracts, futures, swaps, options, and other contracts.

Derivative instruments associated with non-trading activities are accounted for at fair value in accordance with SFAS No. 133 and ongoing interpretations of the FASB's DIG. Derivative and other financial instruments associated with trading activities in electric and other energy commodities are accounted for at fair value in accordance with SFAS No. 133 and EITF 98-10, subject to the transition requirements of the rescission of EITF 98-10 discussed above.

Both non-trading and trading derivatives are classified as price risk management assets and price risk management liabilities in the accompanying Consolidated Balance Sheets. Non-trading derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. For non-trading derivatives that are effective hedges, changes in the fair value are recognized in accumulated other comprehensive income (loss) until the hedged item is recognized in earnings. Derivatives associated with trading activities are adjusted to fair value through income, subject to the effects of the rescission of EITF 98-10 discussed above.

Net realized gains or losses on non-trading derivative instruments for the year ended December 31, 2002, were included in various lines on the PG&E Corporation 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. Changes in the market value of the trading contracts, 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. On an

unrealized and a realized basis, PG&E Corporation now recognizes trading contracts on a net basis as previously described in this Note.

As described more fully in this Note under *Change in Estimate Due to Changes in Certain Fair Value Assumptions*, for non-trading and trading contracts, models are used to estimate the fair value of derivatives and other contracts that are accounted for as derivative contracts. Gross mark-to-market value is estimated using the midpoint of quoted bid and ask prices for liquid periods and, for illiquid periods, using the midpoint of the marginal cost curve and the forecast curve. Interpolation methods are used for intermediate periods when broker quotes are intermittent. The gross mark-to-market valuation is then adjusted for time value of money, creditworthiness of contractual counterparties, market liquidity in future periods, and other adjustments necessary to determine fair value.

PG&E Corporation engages in non-trading activities to hedge the impact of market fluctuations on energy commodity prices, interest rates, and foreign currencies. Before the implementation of SFAS No. 133, 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 that requires that all derivatives, as defined, are recognized 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 $333 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.

PG&E Corporation and the Utility also have 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. The FASB has approved two interpretations issued by the DIG that changed the definition of normal purchases and sales for certain power contracts. As previously described in this Note under "*Changes to Accounting for Certain Derivative Contracts*," PG&E Corporation implemented these interpretations on 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).

Stock-Based Compensation

PG&E Corporation and the Utility account for stock-based compensation using the intrinsic value method in accordance with the provisions of APB No. 25, as allowed by SFAS No. 123, as amended by SFAS No. 148. Under the intrinsic value method, PG&E Corporation and the Utility do 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)	Year ended December 31,		
	2002	2001	2000
Net earnings (loss):			
As reported	$ (874)	$ 1,099	$ (3,364)
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(20)	(23)	(10)
Proforma	$ (894)	$ 1,076	$ (3,374)
Basic earnings (loss) per share:			
As reported	$ (2.36)	$ 3.03	$ (9.29)
Proforma	$ (2.41)	$ 2.96	$ (9.32)
Diluted earnings (loss) per share:			
As reported	$ (2.36)	$ 3.02	$ (9.29)
Proforma	$ (2.41)	$ 2.96	$ (9.32)

Had compensation expense been recognized using the fair value-based method under SFAS No. 123, the Utility's pro forma consolidated earnings (loss) and earnings (loss) per share would have been as follows:

(in millions, except per share amounts)	Year ended December 31,		
	2002	2001	2000
Net earnings (loss):			
As reported	$ 1,794	$ 1,015	$ (3,483)
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(7)	(7)	(5)
Proforma	$ 1,787	$ 1,008	$ (3,488)

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) reports a measure for accumulated changes in equity of an enterprise that results 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.

Reclassifications

Certain amounts in the 2001 and 2000 financial statements have been reclassified to conform to the 2002 presentation. These reclassifications did not affect the consolidated net income of either PG&E Corporation or the Utility for the years presented.

2002 Revision

Subsequent to the issuance of PG&E Corporation's 2002 Consolidated Financial Statements, management discovered a misclassification of certain offsetting revenues and expenses within the discontinued operations of PG&E NEG. As a result, PG&E Corporation's Note 6 of the Notes to the Consolidated Financial Statements has been revised to reflect the reclassification. The reclassification resulted in a decrease in 2002 Operating Revenues in the table in Note 6 from $1,289 million to $822 million and a similar decrease in Operating Expenses Cost of Commodity Sales and Fuel from $993 million to $526 million. The reclassification did not result in a change in the Consolidated Statement of Operations, the Consolidated Balance Sheets or the Consolidated Statements of Cash Flows.

NOTE 2: THE UTILITY CHAPTER 11 FILING

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 mandate included a retail electricity rate freeze and 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 sell more than 50 percent of its fossil fuel-fired generation facilities and made it economically unattractive for the Utility to retain its remaining generation facilities. The new market framework called for the creation of the Power Exchange (PX) and the Independent System Operator (ISO). Before it ceased operating in January 2001, the PX established market-clearing prices for electricity. The ISO's role is 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 (customers who chose to buy from independent power generators or retail electricity suppliers are referred to as direct access customers). Most of the Utility's customers continued to buy electricity from the Utility.

For the seven-month period from June 2000 through December 2000, wholesale electric prices in California averaged $0.18 per kilowatt-hour (kWh). During this period, the Utility's retail electric rates were frozen and provided only approximately $0.05 per kWh to pay for the Utility's electricity costs.

The frozen rates were designed to allow the Utility to recover its authorized utility costs and, to the extent the frozen rates generated revenues in excess of the Utility's authorized utility costs, recover its transitions costs. During the California energy crisis, frozen rates were insufficient to cover the Utility's electricity procurement and other costs. Because the Utility could no longer conclude that its under-collected electricity procurement and remaining transition costs were probable of recovery, the Utility charged $6.9 billion to expense for these costs at December 31, 2000. The Utility's inability to recover procurement costs from customers ultimately resulted in billions of dollars in defaulted debt and unpaid bills and caused the Utility to file a voluntary petition for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court on April 6, 2001.

In January 2001, the CPUC increased electric rates by $0.01 per kWh, and in March 2001 by another $0.03 per kWh, and restricted use of these surcharge revenues to "ongoing procurement costs" and "future power purchases." The Utility had recorded a regulatory liability for these $0.01 and $0.03 surcharge revenues when such surcharges exceeded ongoing procurement costs.

Although the CPUC authorized the $0.03 per kWh surcharge in March 2001, the Utility did not begin collecting the revenues until June 2001. As a result, in May 2001, the CPUC authorized the Utility to collect an additional $0.005 per kWh in revenues for 12 months to make up for the time lag in collection of the $0.03 surcharge revenues. Although the collection of this "half-cent" surcharge was originally scheduled to end on May 31, 2002, the CPUC issued a resolution ordering the Utility to continue collecting the half-cent surcharge until further consideration by the CPUC and to record the surcharge revenues in a balancing account. The Utility had recorded a regulatory liability for the $0.005 per kWh (half-cent) surcharge revenues billed subsequent May 31, 2002. The regulatory liabilities for the $0.01 per kWh and $0.03 per kWh surcharge revenues in excess of ongoing procurement costs, and half-cent surcharge revenues billed after May 31, 2002, totaled $222 million as of September 30, 2002, and $65 million as of December 30, 2001.

In November 2002, the CPUC approved a decision modifying the restrictions on the use of revenues generated by the surcharges to permit the revenues to be used for the purpose of securing or restoring the Utility's reasonable financial health, as determined by the CPUC. The CPUC will determine in other proceedings how the surcharge revenues can be used, whether there is any cost or other basis to support specific surcharge levels, and whether the resulting rates are just and reasonable. After the CPUC determines when the AB 1890 rate freeze ended, the CPUC will determine the extent and disposition of the Utility's under-collected costs, if any, remaining at the end of the rate freeze. If the CPUC determines that the Utility recovered revenues in excess of its transition costs or in excess of other permitted uses, the CPUC may require the Utility to refund such excess revenues.

In a case currently pending before it relating to the CPUC's settlement with Southern California Edison (SCE), another California investor-owned utility (IOU), the Supreme Court of California is considering whether the CPUC has the authority to enter into a settlement which allows SCE to recover under-collected procurement and transition costs in light of the provisions of AB 1890. The Utility cannot predict the outcome of this case or whether the CPUC or others would attempt to apply any ruling to the Utility. If the Utility is ordered to refund material amounts to ratepayers, the Utility's financial condition and results of operations would be materially adversely affected.

In December 2002, the CPUC issued a decision authorizing the Utility to stop tracking amounts related to the $0.01 and $0.03 surcharge revenues in a separate regulatory liability account and instead record them as a reduction to unrecovered transition costs. As a result, in January 2003, the Utility filed a letter with the CPUC requesting to withdraw its regulatory liability account used to track the $0.01 and $0.03 surcharge revenues in excess of ongoing procurement costs.

Based on this December 2002 CPUC decision and an agreement between the CPUC and SCE, in which SCE was allowed to use its half-cent surcharge to offset its California Department of Water Resources (DWR) revenue requirement, the Utility reversed its regulatory liabilities totaling $222 million related to the $0.01 and $0.03 per kWh surcharge revenues in excess of ongoing procurement costs, and half-cent surcharge revenues billed subsequent to May 31, 2002 during the fourth quarter of 2002. (Of this amount, $157 million was originally recorded as a regulatory liability during 2002; and as such, the reversal of this amount has no impact on current year earnings.)

During 2001, the price of wholesale electricity stabilized. As a result, the Utility's total generation-related electric revenues were greater than its generation-related costs. In 2001, this resulted in additional earnings of $458 million (after-tax), which represented a partial recovery of previously written-off under-collected purchased power and transition costs, and included $327 million (after-tax) related to the market value of terminated bilateral contracts. During the year ended December 31, 2002, the Utility's total generation-related revenues exceeded its generation-related costs by approximately $1.4 billion (after-tax), which includes a net reduction of 2001 accrued purchased power costs of approximately $352 million (after-tax) and includes an offset of $218 million (after-tax) in additional pass-through revenues accrued in 2002 related to amounts to be remitted to the DWR in connection with the DWR's proposed amendment to the CPUC's May 16, 2002, servicing order. (See further discussion below under "Electricity Purchases.") The outstanding balance of the Utility's under-collected purchased power and transition costs (which were originally $4.1 billion, after-tax) amounted to $2.2 billion and $3.6 billion (after-tax) at December 31, 2002, and 2001, respectively. The recovery of these remaining under-collected purchased power costs and transition costs will depend on a number of factors, including the ultimate outcome of the Utility's bankruptcy and future regulatory and judicial proceedings, including the outcome of the Utility's filed rate doctrine litigation. (The filed rate doctrine litigation refers to a lawsuit filed in November 2000 in the U.S. District Court for the Northern District of California by the Utility against the CPUC Commissioners, asking the court to declare that the federally approved wholesale electricity costs that the Utility has incurred to serve its customers are recoverable in retail rates under the federal filed rate doctrine.)

Under AB 1890, the rate freeze was scheduled to end on the earlier of March 31, 2002, or the date that the Utility recovered all of its generation-related transition costs as determined by the CPUC. However, in January 2002, the CPUC issued a decision finding that new California legislation, AB 6X,

had materially affected the implementation of AB 1890. The CPUC scheduled further proceedings to address the impact of AB 6X on the AB 1890 rate freeze for the Utility and to determine the extent and disposition of the Utility's remaining unrecovered transition costs. In its November 2002 decision regarding the surcharge revenues, discussed above, the CPUC reiterated that it had yet to decide when the rate freeze ended and the disposition of any under-collected costs remaining at the end of the rate freeze.

The CPUC and the Official Committee of Unsecured Creditors (OCC) filed an alternative plan of reorganization in the Utility's bankruptcy proceeding, proposing that the Utility's overall retail electric rates be maintained at current levels through January 31, 2003, in order to generate cash to repay in part the Utility's creditors under the CPUC's plan. (See "CPUC/OCC's Alternative Plan of Reorganization" below.) During the third quarter of 2002, the CPUC represented that since utilities are now required under state law, AB 6X, to retain their generating assets and the CPUC has regained its traditional rate authority over those assets, costs associated with those assets may be recovered by the utilities in the traditional way, under cost-based regulation. Based on these CPUC decisions and representations, the Utility believes it can continue to record revenues collected under its existing overall retail rates, subsequent to the statutory end of the rate freeze.

However, the CPUC's proceedings to consider the impact of AB 6X on the AB 1890 rate freeze and the disposition of the Utility's unrecovered transition costs are still pending, and it is possible that at some future date the CPUC, on its own initiative or in response to judicial decisions, including the California Supreme Court's consideration regarding the authority of the CPUC to enter into a settlement which allows SCE to recover under-collected procurement and transition costs in light of the provisions of AB 1890, may change its interpretation of law or otherwise seek to change the Utility's overall retail electric rates retroactively. The Utility has not provided reserves for potential refunds of any of these revenues as of December 31, 2002. As a result, any of the changes described above could materially affect the Utility's earnings.

In a March 2001 decision, the CPUC adopted an accounting proposal by The Utility Reform Network (TURN) that retroactively restates the way in which the Utility's transition costs are recovered. This retroactive change had the effect of extending the AB 1890 rate freeze and reducing the amount of past wholesale electricity costs that could be eligible for recovery from customers. The CPUC, the California Supreme Court, and the Bankruptcy Court denied the Utility's request for rehearing. The Utility is currently appealing this matter to the U.S. District Court for the Northern District of California. The Utility cannot predict the outcome of this matter.

Generation Divestiture

AB 6X, passed by the California Legislature in January 2001, prohibits utilities from divesting their remaining power plants before January 1, 2006. The Utility believes this law does not supersede or repeal an existing law requiring the CPUC to establish a market value for their remaining generating assets by the end of 2001, based on appraisal, sale or other divestiture. The Utility has filed comments on this matter with the CPUC. However, the CPUC has not yet issued a decision.

On January 17, 2002, the Utility filed an administrative claim with the State of California Victim Compensation and Government Claims Board (the Board) alleging that the new law violates the Utility's statutory rights under California's deregulation law (AB 1890). The Utility believes that it has been denied its right to the market value of its retained generating facilities of at least $4.1 billion. On March 7, 2002, the Board formally denied the Utility's claim. Having exhausted remedies before the Board, the Utility filed suit for breach of contract in the California Superior Court on September 6, 2002. On January 9, 2003, the Superior Court granted the State of California's request to dismiss the complaint finding that AB 1890 does not constitute a contract. The Utility has 60 days to file an appeal and intends to do so. 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.

Electricity Purchases

In January 2001, as wholesale electric prices continued to exceed retail rates, the major credit rating agencies lowered their ratings for the Utility and PG&E Corporation to non-investment grade levels. Consequently, the Utility lost access to its bank facilities and capital markets, and could no longer continue buying electricity to deliver to its customers. As a result, in the first quarter of 2001, the California Legislature and the Governor of California authorized the DWR to purchase electricity for the Utility's customers and to issue revenue bonds to finance electricity purchases (governed by AB 1X). Initially, the DWR indicated that it intended to buy electricity 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 electricity to cover the amount of the Utility's net open position not covered by the DWR. In 2001, the Utility accrued approximately $1 billion for these ISO purchases for the period January 17, 2001, through April 6, 2001. However, in 2001, the FERC issued a series of orders directing the ISO to buy electricity only on behalf of creditworthy entities. In March 2002, the FERC denied an application for rehearing and reaffirmed its previous orders finding that the DWR is responsible for paying such ISO charges.

In February 2002, the CPUC approved decisions adopting rates for the DWR, and allowing the DWR to collect power charges and financing charges from ratepayers to provide the revenues needed by the DWR to procure electricity for the customers of the Utility and the other California IOUs for the two-year period ending December 31, 2002.

In March 2002, the CPUC modified its February 2002, DWR revenue requirement decision, effectively lowering the amount allocated to the Utility's customers to $4.4 billion for the period from January 2001 through December 2002. The DWR's revenue requirement incorporates the procurement charges previously billed by the ISO and accrued by the Utility. As such, in light of the March 2002

FERC order and the February and March 2002, CPUC decisions, in the first quarter of 2002 the Utility reversed the excess of the ISO accrual (for the period from January 17, 2001, through April 6, 2001) over the amount of the additional DWR revenue requirement applicable to 2001, for a net reduction of accrued purchased power costs of approximately $595 million (pre-tax).

In October 2002, the DWR filed a proposed amendment to the CPUC's May 16, 2002, servicing order requesting changes to the calculation that determines the amount the Utility is required to pass through to the DWR. The DWR's proposed amendment changes the calculation that determines the amount of revenues that the Utility must pass-through to the DWR. This proposed amendment would also be used to true up previous amounts passed through to the DWR as well as future payments. Under its statutory authority, the DWR may request the CPUC to order utilities to implement such amendments, and the CPUC has approved such amendments in the past without significant change. In December 2002, the CPUC approved an operating order requiring the Utility to perform the operational, dispatch, and administrative functions for the DWR's allocated contracts beginning on January 1, 2003. The operating order, which applies prospectively, includes the DWR's proposed method of calculating the amount of revenues that the Utility must pass-through to the DWR. As a result, as of December 31, 2002, the Utility has accrued an additional $369 million (pre-tax) liability for pass-through revenues for electricity provided by the DWR to the Utility's customers.

In October 2002, the Utility filed a lawsuit in a California court asking the court to find that the DWR's revenue requirements had not been demonstrated to be "just and reasonable" (as required by AB 1X) and lawful, and that the DWR had violated the procedural requirements of AB 1X in making its determination. The Utility asked the court to order the DWR's revenue requirement determination be withdrawn as invalid, and that the DWR be precluded from imposing its revenue requirements on the Utility and its customers until it has complied with the law. No schedule has yet been set for consideration of the lawsuit.

Senate Bill 1976

Under AB 1X, the DWR is prohibited from entering into new agreements to purchase electricity to meet the net open position of the California IOUs after December 31, 2002. In September 2002, the Governor signed California Senate Bill (SB) 1976 into law. SB 1976 required that each California IOU submit, within 60 days after the CPUC allocated existing DWR contracts for electricity procurement to each California IOU, an electricity procurement plan to meet the residual net open position associated with that utility's customer demand. SB 1976 requires that each procurement plan include one or more of the following features:

- A competitive procurement process under a format authorized by the CPUC, with the costs of procurement obtained in compliance with the authorized bidding format being recoverable in rates;

- A clear, achievable, and quantifiable incentive mechanism that establishes benchmarks for procurement and authorizes the IOUs to procure electricity from the market subject to comparison with the CPUC-authorized benchmarks; or

- Upfront and achievable standards and criteria to determine the acceptability and eligibility for rate recovery of a proposed transaction and an expedited CPUC pre-approval process for proposed bilateral contracts to ensure compliance with the individual utility's procurement plan.

SB 1976 provides that the CPUC may not approve the procurement plan if it finds the plan contains features or mechanisms which would impair restoration of the IOU's creditworthiness or would lead to a deterioration of the IOU's creditworthiness. SB 1976 also indicates that procurement activities in compliance with an approved procurement plan will not be subject to after-the-fact reasonableness review. The CPUC is permitted to establish a regulatory process to verify and ensure

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that each contract was administered in accordance with its terms and that contract disputes that arise are resolved reasonably.

A central feature of the SB 1976 regulatory framework is its direction to the CPUC to create new electric procurement balancing accounts to track and allow recovery of the differences between recorded revenues and costs incurred under an approved procurement plan. The CPUC must review the revenues and costs associated with the Utility's electric procurement plan at least semi-annually and adjust rates or order refunds, as appropriate, to properly amortize the balancing accounts. Until January 1, 2006, the CPUC must establish the schedule for amortizing the over-collections or under-collections in the electric procurement balancing accounts so that the aggregate over-collections or under-collections reflected in the accounts do not exceed 5 percent of the IOU's actual recorded generation revenues for the prior calendar year, excluding revenues collected on behalf of the DWR. Mandatory semi-annual review and adjustment of the balancing accounts will continue until January 1, 2006, after which time the CPUC will conduct electric procurement balancing account reviews and adjust retail ratemaking amortization schedules for the balancing accounts as the CPUC deems appropriate and in a manner consistent with the requirements of SB 1976 for timely recovery of electricity procurement costs.

Allocation of DWR Electricity to Customers of the IOUs

Consistent with applicable law and CPUC orders, since 2001, the Utility and the other California IOUs have acted as the billing and collection agents for the DWR's sales of its electricity to retail customers. In September 2002, the CPUC issued a decision allocating the electricity provided under existing DWR contracts to the customers of the IOUs. This decision required the Utility, along with the other IOUs, to begin performing all the day-to-day scheduling, dispatch, and administrative functions associated with the DWR contracts allocated to the IOUs' portfolios by January 1, 2003.

Although the DWR retains legal and financial responsibility for these contracts, the DWR has stated publicly that it intends to transfer full legal title of, and responsibility for, the DWR electricity contracts to the IOUs as soon as possible. However, SB 1976 does not contemplate a transfer of title of the DWR contracts to the IOUs. In addition, the operating order issued by the CPUC in December 2002 implementing the Utility's operational and scheduling responsibility with respect to the DWR allocated contracts specifies that the DWR will retain legal and financial responsibility for the contracts and that the December 2002 order does not result in an assignment of the DWR allocated contracts. The Utility's proposed plan of reorganization prohibits the Utility from accepting, directly or indirectly, assignment of legal or financial responsibility for the DWR contracts. There can be no assurance that either the State of California or the CPUC will not seek to provide the DWR with authority to effect such a transfer of legal title in the future. The Utility has informed the CPUC, the DWR and the State that the Utility would vigorously oppose any attempt to transfer the DWR allocated contracts to the Utility without the Utility's consent.

Chapter 11 Filing

On April 6, 2001, the Utility filed for relief under Chapter 11 of the Bankruptcy Code. Under Chapter 11, the Utility is subject to the jurisdiction of the Bankruptcy Court, however the Utility has control of its assets and is authorized to operate its business as a debtor-in-possession. 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 Chapter 11 filing. PG&E Corporation, the Utility's parent, and PG&E NEG have not filed for Chapter 11 and are not included in the Utility's Chapter 11 filing. PG&E Corporation, however, is a co-proponent of the Utility's proposed plan of reorganization.

In connection with the Utility's Chapter 11 filing, various parties have filed claims with the Bankruptcy Court. Through December 31, 2002, claims filed with the Bankruptcy Court totaled approximately $49.4 billion. Of the $49.4 billion of claims filed, claims for approximately $25.5 billion have been disallowed by the Bankruptcy Court due to objections submitted by the Utility or as a result of the claimants withdrawing their claims from the Bankruptcy Court. Of the remaining $23.9 billion of filed claims, pursuant to the Plan and alternative plan (discussed below), claims totaling approximately $6.6 billion are expected to pass through the bankruptcy proceeding and be determined in the appropriate court or other tribunal during the bankruptcy proceeding or after it concludes.

The Utility intends to object to approximately $4.3 billion of the remaining $23.9 billion of filed claims. These objections relate primarily to generator claims. Approximately $500 million of the $23.9 billion of filed claims are subject to pending Utility objections. The Utility has recorded its estimate of all valid claims at December 31, 2002, as $9.4 billion of Liabilities Subject to Compromise and $3.0 billion of Long-Term Debt. The Utility has paid certain claims authorized by the Bankruptcy Court, as discussed below, and reduced the amount of outstanding claims accordingly. In addition, since its Chapter 11 filing, the Utility has accrued interest on all claims the Utility considers valid. This additional interest accrual is not included in the original $49.4 billion of claims filed. The following schedule summarizes the activity of the Utility's Liabilities Subject to Compromise from the period of December 31, 2001 to December 31, 2002.

(in billions)

(in billions)

Liabilities Subject to Compromise at December 31, 2001	$ 11.4
Interest accrual for the year ended December 31, 2002	0.3
Claims paid pursuant to Bankruptcy Court orders	(1.4)
Claims and Interest authorized by the Bankruptcy Court to be paid (transferred to accounts payable or interest payable)	(0.2)
Reclassification of debt upon liquidation of trust holding solely Utility Subordinated Debentures (Note 4)	0.3
Reversal of first quarter 2001 ISO accrual	(1.0)
Liabilities Subject to Compromise at December 31, 2002	$ 9.4
Claims filed by PG&E Corporation and included in Liabilities Subject to Compromise	(0.2)
Liabilities Subject to Compromise at December 31, 2002, excluding claims payable to PG&E Corporation	$ 9.2

The balance of Liabilities Subject to Compromise increases and decreases due to a variety of factors. For example, disputed claims may be resolved or the Bankruptcy Court may authorize payment of certain claims.

The Bankruptcy Court has authorized the Utility to pay certain pre-petition claims and pre- and post-petition interest on certain claims prior to emerging from Chapter 11. Pursuant to Bankruptcy Court authorization, through December 31, 2002, approximately $901 million in principal and $60 million in interest had been paid to qualifying facilities (QFs). The Bankruptcy Court has also authorized the Utility to pay all undisputed creditor claims that amount to $5,000 or less and undisputed mechanics' lien and reclamation claims. At December 31, 2002, the majority of these payments had been made and totaled approximately $10 million. Also pursuant to Bankruptcy Court authorization, the Utility has paid approximately $1.3 billion through January 2, 2003, for pre- and post-petition interest on certain undisputed claims. The Utility also repaid advances and interest on advances of approximately $25 million, through January 2, 2003, to banks providing letters of credit backing pollution control bonds. In addition, the Utility has paid approximately $79 million in refunds for customer deposits, reimbursements for work performed by customers, and inspection fees for contracts related to gas and electric line extensions. A portion of these refunds, reimbursements, and inspection fees were paid as part of the Utility's normal business operations, and were not included in claims filed with the Bankruptcy Court.

As discussed above, the Bankruptcy Court has authorized payment of certain claims. These claims are therefore not included in the $9.4 billion of Liabilities Subject to Compromise, however the Utility is paying interest on these other claims at the various rates as described below. For certain claims, the Utility has identified receivable balances owed to the Utility from the claimant. These receivable

balances may be settled as offsets to claims filed by the claimant, thereby reducing the amount of the claim and the interest ultimately payable to the claimant.

As specified in the Utility's proposed plan of reorganization (the Plan) described below, the Utility has agreed to pay pre- and post-petition interest on Liabilities Subject to Compromise at the rates set forth below, plus additional interest on certain claims as discussed below.

	Amount Owed (in millions)	Agreed Upon Rate (per annum)	
Commercial Paper Claims	$ 873	7.466%	
Floating Rate Notes	1,240	7.583%	(Implied yield of 7.690%)
Senior Notes	680	9.625%	
Medium-Term Notes	287	5.810% to 8.450%	
Revolving Line of Credit Claims	938	8.000%	
Majority of QFs	97	5.000%	
Other Claims	5,276	Various	

	Amount Owed (in millions)	Agreed Upon Rate (per annum)
Liabilities Subject to Compromise at December 31, 2002	$ 9,391	

Since the Plan did not become effective on or before February 15, 2003, the interest rates for Commercial Paper Claims, Floating Rate Notes, Senior Notes, Medium-Term Notes, and Revolving Line of Credit Claims have been increased by 37.5 basis points, for periods on and after February 15, 2003. If the Plan does not become effective on or before September 15, 2003, the interest rates for these claims on and after such date will be increased by an additional 37.5 basis points. Finally, if the effective date does not occur on or before March 15, 2004, the interest rates for these claims on and after such date will be increased by an additional 37.5 basis points. For other claims, the Utility has recorded interest at the contractual or FERC-tariffed interest rate. When those rates do not apply, the Utility has recorded interest at the federal judgment rate.

The Utility has received approval from the Bankruptcy Court to make certain pre-petition principal payments on secured debt that has matured and has, at December 31, 2002, paid $333 million on this debt. At December 31, 2002, the Utility has $3 billion outstanding in pre-petition principal, secured debt. This debt is classified as Long-Term Debt in the Consolidated Balance Sheets.

The Bankruptcy Court has also authorized certain payments and actions necessary for the Utility to continue its normal business operations while operating as a debtor-in-possession. For example, the Utility is authorized to pay employee wages and benefits, certain QFs, interest on secured debt, environmental remediation expenses, and expenditures related to property, plant and equipment. In addition, the Utility is authorized to refund certain customer deposits, use certain bank accounts and cash collateral, and assume responsibility for various hydroelectric contracts.

Proposed Plan of Reorganization

The Utility and PG&E Corporation have jointly proposed a plan of reorganization, referred to as the Plan, which would allow the Utility to restructure its businesses and refinance the restructured businesses. The Plan is designed to align the Utility's existing businesses under the regulators that best match the business functions. Retail assets (natural gas and electricity distribution) would remain under the retail regulator, the CPUC. The wholesale assets (electric transmission, interstate natural gas transportation, and electric generation) would be placed under wholesale regulators, the FERC and the Nuclear Regulatory Commission (NRC). After this realignment, the retail-focused business would be a natural gas and electricity distribution company (Reorganized Utility), representing approximately 70 percent of the book value of the Utility's assets.

In contemplation of the Plan becoming effective, the Utility has created three new limited liability companies, the LLCs, which currently are owned by the Utility's wholly owned subsidiary, Newco Energy Corporation, or Newco. On the effective date of the Plan, the Utility would transfer substantially all the assets and liabilities primarily related to the Utility's electricity generation business to Electric Generation LLC, or Gen; the assets and liabilities primarily related to the Utility's electricity transmission business to ETrans LLC, or ETrans; and the assets and liabilities primarily related to the Utility's natural gas transportation and storage business to GTrans LLC, or GTrans.

The Plan proposes that on the effective date, the Utility would distribute to PG&E Corporation 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, on the effective date of the Plan or as promptly thereafter as practicable, PG&E Corporation would distribute all the shares of the Utility's common stock that it then holds to its existing shareholders in a spin-off transaction. After the spin-off, the Reorganized Utility would be an independent publicly held company. The common stock of the Reorganized Utility would be registered under federal securities laws and would be freely tradable by the recipients on the effective date or as soon as practicable thereafter. The Reorganized Utility would apply to list its common stock on the New York Stock Exchange. The Reorganized Utility would retain the name "Pacific Gas and Electric Company."

Although the Reorganized Utility would be legally separated from the LLCs, the Reorganized Utility's operations would remain connected to the operations of the LLCs after the effective date of the Plan. For example:

- The Reorganized Utility would rely on Gen for a significant portion of the electricity the Reorganized Utility needs to meet its electricity distribution customers' demand during the 12-year term of a power purchase and sale agreement between the Reorganized Utility and Gen, or the Gen power purchase and sale agreement.

The Reorganized Utility would rely on ETrans for the Reorganized Utility's electricity transmission needs because the transmission lines proposed to be transferred to ETrans are currently the only transmission lines directly connected to the Utility's electricity distribution system.

The Reorganized Utility would rely on GTrans for the Reorganized Utility's natural gas transportation needs because the facilities proposed to be transferred to GTrans are currently the only transportation facilities directly connected to the Utility's natural gas distribution system. In addition, the Reorganized Utility would rely on GTrans for a substantial portion of the Reorganized Utility's natural gas storage requirements for at least 10 years under a transportation and storage services agreement between the Reorganized Utility and GTrans, though the Utility does have storage options with third party providers to meet a portion of their requirements.

The Reorganized Utility also would have significant operating relationships with the LLCs covering a range of functions and services.

Finally, the Reorganized Utility would continue to rely on its natural gas transportation agreement with PG&E GTN, for the transportation of western Canadian natural gas.

During 2002, the Utility undertook several initiatives to prepare for separation under the Plan. The Utility has spent approximately $43 million through December 31, 2002, on these initiatives.

The Plan proposes that allowed claims would be satisfied by cash, long-term notes issued by the LLCs or a combination of cash and such notes. Each of ETrans, GTrans, and Gen would issue long-term notes to the Reorganized Utility and the Reorganized Utility would then transfer the notes to certain holders of allowed claims. In addition, each of the Reorganized Utility, ETrans, GTrans, and

Gen would issue "new money" notes in registered public offerings. The LLCs would transfer the proceeds of the sale of the new money notes, less working capital reserves, to the Utility for payment of allowed claims. The Plan also would reinstate nearly $1.59 billion of preferred stock and pollution control loan agreements.

On February 19, 2003, Standard & Poor's (S&P), a major credit rating agency, announced that it had re-affirmed its preliminary rating evaluation, originally issued in January 2002, of the corporate credit ratings of, and the securities proposed to be issued by the Reorganized Utility and the LLCs in connection with the implementation of the Utility Plan. Subject to the satisfaction of various conditions, S&P stated that the approximately $8.5 billion of securities proposed to be issued by the Reorganized Utility and the LLCs, as well as their corporate credit ratings, would be capable of achieving investment grade ratings of at least BBB-. In order to satisfy some of the conditions specified by S&P, on February 24, 2003, the Utility filed amendments to the Utility Plan with the Bankruptcy Court that, among other modifications:

permit the Reorganized Utility and the LLCs to issue secured debt instead of unsecured debt,

permit adjustments in the amount of debt the Reorganized Utility and the LLCs would issue so that additional new money notes could be issued if additional cash is required to satisfy allowed claims or to deposit in escrow for disputed claims and such debt can be issued while maintaining investment grade ratings, or so that less debt could be issued in order to obtain investment grade ratings or if less cash is required to satisfy allowed claims and be deposited into escrow for disputed claims,

require Gen to establish a debt service reserve account and an operating reserve account,

under certain circumstances, permit an increase in the amount of cash creditors receiving cash and notes will receive, permit the Utility's mortgage-backed pollution control bonds to be redeemed if the Reorganized Utility issues secured new money notes, and

commit PG&E Corporation to contribute up to $700 million in cash to the Utility's capital from the issuance of equity or from other available sources, to the extent necessary to satisfy the cash obligations of the Utility in respect of allowed claims and required deposits into escrow for disputed claims, or to obtain investment grade ratings for the debt to be issued by the Reorganized Utility and the LLCs.

In addition to the amendments to the Plan, amendments to various filings at the FERC, and possibly other regulatory agencies, will be required in order to implement the changes to the Plan.

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

The effective date of the Plan shall be on or before May 30, 2003;

All actions, documents, and agreements necessary to implement the Plan shall have been effected or executed;

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;

S&P and Moody's shall have established investment-grade 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;

The Plan shall not have been modified in a material way since the confirmation date; and

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 May 30, 2003, the confirmation order would be vacated. The Utility's obligations with respect to claims and equity interests would remain unchanged.

PG&E Corporation and the Utility contend that bankruptcy law expressly preempts state law in connection with the implementation of a plan of reorganization. The Bankruptcy Court rejected this contention. PG&E Corporation and the Utility appealed the express preemption aspect of this decision to the U.S. District Court. The U.S. District Court reversed the Bankruptcy Court's ruling and remanded the case back to the Bankruptcy Court for further proceedings, ruling that the Bankruptcy Code expressly preempts "nonbankruptcy laws that would otherwise apply to bar, among other things, transactions necessary to implement the reorganization plan." The U.S. District Court entered judgment on September 19, 2002, and the CPUC and several other parties thereafter initiated an appeal to the U.S. Court of Appeals for the Ninth Circuit, which is pending.

The CPUC/OCC's Alternative Plan of Reorganization

The CPUC and the OCC have jointly proposed an alternative plan of reorganization for the Utility that does not call for realignment of the Utility's existing businesses. The alternative plan instead provides for the continued regulation of all of the Utility's current operations by the CPUC. The alternative plan proposes to satisfy all allowed creditor claims in full either through reinstatement or payment in cash, using a combination of cash on hand and the proceeds from the issuance of $7.3 billion of new senior secured debt and the issuance of $1.5 billion of new unsecured debt and preferred securities. The alternative plan proposes to establish a $1.75 billion regulatory asset, which would be amortized over ten years and would earn the full rate of return on rate base.

The CPUC/OCC Plan also provides that it would not become effective until the Utility and the CPUC enter into a "reorganization agreement" under which the CPUC promises to establish retail electric rates on an ongoing basis sufficient for the Utility to achieve and maintain investment grade credit ratings and to recover in rates (1) the interest and dividends payable on, and the amortization and redemption of, the securities to be issued under the alternative plan, and (2) certain recoverable costs (defined as the amounts the Utility is authorized by the CPUC to recover in retail electric rates in accordance with historic practice for all of its prudently incurred costs, including capital investment in property, plant and equipment, a return of capital and a return on capital and equity to be determined by the CPUC from time to time in accordance with its past practices).

PG&E Corporation and the Utility believe the alternative plan is not credible or confirmable. PG&E Corporation and the Utility do not believe the alternative plan would restore the Utility to investment grade status if the alternative plan were to become effective. Additionally, PG&E Corporation and the Utility believe the alternative plan would violate applicable federal and state law.

Confirmation Hearings

Solicitation of creditor votes began on June 17, 2002, and concluded on August 12, 2002. On September 9, 2002, an independent voting agent filed the voting results with the Bankruptcy Court. Nine of the ten voting classes under the Utility's proposed plan of reorganization approved the Plan. The alternative plan was approved by one of the eight voting classes under the alternative plan.

On November 6, 2002, the CPUC and the OCC filed an amended alternative plan and filed a motion asking the Bankruptcy Court to authorize the resolicitation of creditor votes and preferences. The Bankruptcy Court heard oral arguments on November 27, 2002. On February 6, 2003, the Bankruptcy Court issued an order denying the CPUC's and the OCC's request.

In determining whether to confirm either plan, the Bankruptcy Court will consider creditor and equity interests, plan feasibility, distributions to creditors and equity interests, and the financial viability of the reorganized entities. Various parties have filed objections to confirmation of either or both plans. PG&E Corporation and the Utility filed objections to the alternative plan stating their belief that the alternative plan is neither feasible nor confirmable for the reasons discussed above. The CPUC also filed an objection to the Plan.

The trial on confirmation of the alternative plan began on November 18, 2002. The trial on the Plan began on December 16, 2002, with objections common to both plans slated for trial during the Plan trial.

The Utility is unable to predict which plan, if any, the Bankruptcy Court will confirm. If either plan is confirmed, implementation of the confirmed plan may be delayed due to appeals, CPUC actions or proceedings, or other regulatory hearings that could be required in connection with the regulatory approvals necessary to implement that plan, and other events. The uncertainty regarding the outcome of the bankruptcy proceeding and the related uncertainty around the plan of reorganization that is ultimately adopted and implemented will have a significant impact on the Utility's future liquidity and results of operations. The Utility is unable at this time to predict the outcome of its bankruptcy case or the effect of the reorganization process on the claims of the Utility's creditors or the interests of the Utility's preferred shareholders. However, the Utility believes, based on information presently available to it, that cash and cash equivalents on hand at December 31, 2002, of $3.3 billion and cash available from operations will provide sufficient liquidity to allow it to continue as a going concern through 2003.

NOTE 3: PG&E NEG LIQUIDITY MATTERS

During 2002, adverse changes in the electric power and gas utility industry and energy markets affected PG&E Corporation, the Utility and PG&E NEG business including:

- Contractions and instability of wholesale electricity and energy commodity markets;
- Significant decline in generation margins (spark spreads) caused by excess supply and reduced demand in most regions of the United States;
- Loss of confidence in energy companies due to increased scrutiny by regulators, elected officials, and investors as a result of a string of financial reporting scandals;

Heightened scrutiny by credit rating agencies prompted by these market changes and scandals which resulted in lower credit ratings for many market participants; and

Resulting significant financial distress and liquidity problems among market participants leading to numerous financial restructurings and less market participation.

PG&E NEG has been significantly impacted by these changes in 2002. New generation came online while the economic recession reduced demand. This oversupply and reduced demand resulted in low spark spreads (the net of power prices less fuel costs) and depressed operating margins. These changes in the power industry have had a significant negative impact on the financial results and liquidity of PG&E NEG.

Before July 31, 2002, most of the various debt instruments of PG&E NEG and its affiliates carried investment-grade credit ratings as assigned by S&P and Moody's, two major credit rating agencies. Since July 31, 2002, PG&E NEG's rated entities have been downgraded several times. The result of these downgrades had left all of PG&E NEG's rated entities and debt instruments at below investment grade.

The downgrade of PG&E NEG's credit ratings impacts various guarantees and financial arrangements that require PG&E NEG to maintain certain credit ratings by S&P and/or Moody's. PG&E NEG's counterparties have demanded that PG&E NEG provide additional security for performance in the form of cash, letters of credit, acceptable replacement guarantees, or advanced

funding of obligations. Other counterparties continue to have the right to make such demands. If PG&E NEG fails to provide this additional collateral within defined cure periods, PG&E NEG may be in default under contractual terms. In addition to agreements containing ratings triggers, other agreements allow counterparties to seek additional security for performance whenever such counterparty becomes concerned about PG&E NEG's or its subsidiaries' creditworthiness. PG&E NEG's credit downgrade constrains its access to additional capital and triggers increases in cost of indebtedness under many of its outstanding debt arrangements.

The credit downgrade also impacted PG&E NEG's and its subsidiaries' ability to service their financial obligations by putting constraints on the ability to move cash from one subsidiary to another or to PG&E NEG itself. PG&E NEG's subsidiaries must now independently determine, in light of each company's financial situation, whether any proposed dividend, distribution or intercompany loan is permitted and is in such subsidiary's interest.

PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling approximately $2.5 billion, but this debt is non-recourse to PG&E NEG. On November 14, 2002, PG&E NEG defaulted on the repayment of the $431 million 364-day tranche of its Corporate Revolver. The amount outstanding under the two-year tranche of the Corporate Revolver is $273 million, the majority of which supports outstanding letters of credit. The default under the Corporate Revolver also constitutes a cross-default under PG&E NEG's (outstanding) (1) Senior Notes ($1 billion), (2) guarantee of the Turbine Revolver ($205 million), and (3) equity commitment guarantees for the GenHoldings credit facility ($355 million), for the La Paloma credit facility ($375 million) and for the Lake Road credit facility ($230 million). In addition, on November 15, 2002, PG&E NEG failed to pay a $52 million interest payment due under the Senior Notes.

PG&E Corporation continues to provide assistance to PG&E NEG, its subsidiaries and its lenders in their negotiations to establish a restructuring of PG&E NEG's commitments. However, if these negotiations prove unsuccessful and if lenders exercise their default remedies or if the financial commitments are not restructured, PG&E NEG and certain of its subsidiaries may be compelled to seek protection under or be forced into a proceeding under Chapter 11 of the Bankruptcy Code. Management does not expect the liquidity constraints of PG&E NEG and its subsidiaries will affect the financial condition of PG&E Corporation or the Utility.

Debt in Default and Long-Term Debt

The schedule below summarizes PG&E NEG's outstanding debt in default and long-term debts as of December 31, 2002, and 2001:

(in millions)	Maturity	Interest Rates	Outstanding Balance	
			December 31,	
			2002	2001
Debt in Default [(1)]				
PG&E NEG, Inc. Senior Unsecured Notes	2011	10.375%	$ 1,000	$ 1,000
PG&E NEG, Inc. Credit Facility Tranche B (364 day)	11/14/02	Prime plus credit spread	431	330
PG&E NEG, Inc. Credit Facility Tranche A (2-year facility with a $273 million total commitment)	8/23/03	Prime plus credit spread	42	
Turbine and Equipment Facility	12/31/03	Prime plus credit spread	205	221
GenHoldings Construction Facility Tranche A	12/5/03	LIBOR plus credit spread	118	
GenHoldings Construction Facility Tranche B	12/5/03	LIBOR plus credit spread	1,068	450
GenHoldings Swap Termination			50	
Lake Road Construction Facility Tranche A	12/11/02	Prime plus credit spread	227	206
Lake Road Construction Facility Tranche B	12/11/02	Prime plus credit spread	219	198
Lake Road Construction Facility Tranche C		Prime plus credit spread		13
Lake Road Working Capital Facility	12/09/03	Prime plus credit spread	23	
Lake Road Swap Termination	12/11/02		61	
La Paloma Construction Facility Tranche A	12/11/02	Prime plus credit spread	367	319
La Paloma Construction Facility Tranche B	12/11/02	Prime plus credit spread	291	251
La Paloma Construction Facility Tranche C	12/11/02	Prime plus credit spread	20	18
La Paloma Construction Facility			29	
La Paloma Swap Termination			79	
Subtotal			4,230	3,006
Long-Term Debt				
PG&E GTN Senior Unsecured Notes	2005	7.10%	250	250
PG&E GTN Senior Unsecured Debentures	2025	7.80%	150	150
PG&E GTN Senior Unsecured Notes	2012	6.62%	100	
PG&E GTN Medium Term Notes	Through 2003	6.96%	6	39
PG&E GTN Credit Facility	5/2/05	LIBOR plus credit spread	58	85
USGenNE Credit Facility	9/1/03	LIBOR plus credit spread	75	75
Plains End Construction Facility	9/6/06	LIBOR plus credit spread	56	23
Other non-recourse project term loans	Various	Principally LIBOR plus credit spread		100
Mortgage loan payable	2010	CP rate + 6.07%	7	7
Other	Various	Various	20	17
Subtotal			722	746
Total Debt in default and Long-term debt			$ 4,952	$ 3,752
Amounts classified as:				
Debt in default			$ 4,230	$
Long-term debt, classified as current			17	378
Long-term debt			630	3,299
Amount related to liabilities of operations held for sale, classified as current			75	75
Total Debt in default and Long-term debt			$ 4,952	$ 3,752

(1) Certain PG&E NEG long-term debt has been reclassified under debt in default above and has been classified as current liabilities in the accompanying Consolidated Balance Sheets. These instruments were not in default during 2001.

As of December 31, 2002, scheduled maturities of PG&E NEG debt in default and long-term debt were as follows:

(in millions)

Three months ended March 31, 2003	$ 1,431
Three months ended June 30, 2003	
Three months ended September 30, 2003	42
Three months ended December 31, 2003	2,757
Total debt in default	$ 4,230
2003	92
2004	3
2005	310
2006	52
2007	4
Thereafter	261
Total Long-term debt	$ 722

PG&E NEG Senior Unsecured Notes 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.

On November 15, 2002, PG&E NEG failed to pay a $52 million interest payment due on these notes. At December 31, 2002, PG&E NEG has an outstanding interest payment due on these notes of $65 million.

Credit Facilities In August 2001, PG&E NEG arranged a $1.25 billion working capital and letter of credit facility consisting of a $750 million tranche with a 364-day term and a $500 million tranche with a two-year term. On October 21, 2002, the available commitments were reduced to $431 million and $279 million, respectively. As of December 31, 2002, $431 million had been drawn against the 364-day revolving credit facility and $42 million had been drawn against the two-year facility, in addition to $231 million of letters of credit issued under the two-year facility. At December 31, 2002, PG&E NEG had outstanding interest accrued on these facilities of $6 million.

PG&E NEG also has other revolving credit facilities held by subsidiaries. These facilities relate specifically to funding requirements of these entities and are not available to PG&E NEG. Under the terms of the various revolving credit facilities, the credit spread component of the interest rates and fees charged for borrowings was increased as a result of PG&E NEG's credit downgrades. PG&E NEG's credit downgrades did not trigger any acceleration of payments due under these long-term debt arrangements.

PG&E GTN Credit Facility On May 2, 2002, PG&E GTN entered into a three-year $125 million revolving credit facility. At December 31, 2002, there was $58 million outstanding under this facility. The average weighted interest rate on the amount outstanding at December 31, 2002 is approximately 2.89 percent.

Turbine and Equipment Facility 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 average weighted interest rate on the amount outstanding at December 31, 2002 is approximately 4.66 percent.

USGenNE Credit Facility In August 2001, USGenNE entered into a credit and letter of credit facility that has a total commitment of $100 million of which $75 million have been drawn upon and $13 million supports letters of credit that have been issued and are outstanding at December 31, 2002. Total amounts outstanding under this facility, including any accrued interest are included in Liabilities of operations held for sale on the Consolidated Balance Sheets. See Note 6 Discontinued Operations. The average weighted interest rate on the amount outstanding is approximately 2.61 percent.

GenHoldings Construction Facility In December 2001, PG&E NEG entered into a $1.075 billion 5-year non-recourse credit facility, which increased to $1.46 billion on April 5, 2002, for the GenHoldings I, LLC, (GenHoldings) portfolio of projects secured by the Millennium, Harquahala, Covert, and Athens projects. The facility was intended to be used to reimburse PG&E NEG and lenders for a portion of the construction costs already incurred on these projects and to fund a portion of the balance of the construction costs through completion.

GenHoldings has defaulted under its credit agreement by failing to make equity contributions to fund construction draws for the Athens, Harquahala, and Covert generating projects. Through December 31, 2002, GenHoldings has contributed $833 million of equity to the projects. Although PG&E NEG has guaranteed GenHoldings' obligation to make equity contributions, PG&E NEG has notified the GenHoldings lenders that it will not make further equity contributions on behalf of GenHoldings. In November and December 2002, the lenders executed waivers and amendments to the credit agreement under which they agreed to continue to waive until March 31, 2003, the default caused by GenHoldings' failure to make equity contributions. In addition, certain of these lenders agreed to increase their loan commitments to an amount sufficient to provide (1) the funds necessary to complete construction of the Athens, Covert and Harquahala facilities; and (2) additional working capital facilities to enable each project, including Millennium, to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent transmission system operator requirements. The November and December 2002 increased loan commitments are senior to the original liens and rank equally with each other but are senior to amounts loaned through and including the October credit extension. As a result, on November 25, 2002, the funding lenders paid GenHoldings' then pending draw request of approximately $75 million and on December 23, 2002, the funding lenders paid GenHoldings' then pending draw request of approximately $44 million.

In connection with the lenders' waiver of various defaults and additional funding commitments, PG&E NEG has agreed to cooperate with any reasonable proposal by the lenders regarding disposition of the equity in or assets of any or all of the PG&E NEG subsidiaries holding the Athens, Covert, Harquahala and Millennium projects. The amended credit agreement provides that an event of default will occur if the Athens, Covert, Harquahala and Millennium facilities are not transferred to the lenders or their designees on or before March 31, 2003. Such a default would trigger lender remedies, including the right to foreclose on the projects.

Under the waiver, PG&E NEG has re-affirmed its guarantee of GenHoldings' obligation to make equity contributions to these projects of approximately $355 million. Neither PG&E NEG nor GenHoldings currently expects to have sufficient funds to make this payment. The requirement to pay $355 million will remain an obligation of PG&E NEG that would survive the transfer of the projects.

Further, as a result of GenHoldings' failure to make required payments under the interest rate hedge contracts entered into by GenHoldings, the counterparties to such interest rate hedge contracts terminated the contracts during December 2002. Settlement amounts due by GenHoldings in connection with such terminated contracts are, in the aggregate, approximately $49.8 million.

Lake Road and La Paloma Construction Facilities In September 1999 and March 2000, Lake Road and La Paloma (respectively) entered into Participation Agreements to finance the construction of the two plants. In 2001, subsequent to the issuance of the 1999 and 2000 financial statements, management determined that the assets and liabilities related to these leased facilities should have been consolidated. In November 2002 Lake Road and La Paloma defaulted on their obligations to pay interest and swap payments. In addition, as a result of PG&E NEG's downgrade to below investment-grade by both S&P and Moody's, PG&E NEG, as guarantor of certain debt obligations of Lake Road and La Paloma, became required to make

equity contributions to Lake Road and La Paloma of $230 million and $375 million respectively. None of PG&E NEG, Lake Road or La Paloma have sufficient funds to make these payments.

As of December 4, 2002, PG&E NEG and certain subsidiaries entered into various agreements with the respective lenders for each of the Lake Road and La Paloma generating projects providing for (1) funding of construction costs required to complete the La Paloma facility; and (2) additional working capital facilities to enable each subsidiary to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent transmission system operator requirements, as well as for general working capital purposes. Lenders extending new credit under these agreements have received liens on the projects that are senior to the existing lenders' liens. These agreements provide, among other things, that the failure to transfer the Lake Road and La Paloma projects to the respective lenders by June 9, 2003 will constitute a default under the agreements. The failure to transfer the facilities would entitle the lenders to accelerate the new indebtedness and exercise other remedies.

In consideration of the lenders' forebearance and additional funding, PG&E NEG had previously agreed to cooperate, and cause its subsidiaries to cooperate, with any reasonable proposal regarding disposition of the ownership interests in and/or assets of the La Paloma project, on terms and conditions satisfactory to the lenders in their sole discretion.

The La Paloma and Lake Road projects have been financed entirely with debt. PG&E NEG has guaranteed the repayment of a portion of the project subsidiary debt in the approximate aggregate amounts of $374.5 million for La Paloma and $230 million for Lake Road, which amounts represent the subsidiaries' equity contribution in the projects. The lenders have accelerated the guaranteed portion of the debt and made a payment demand under the PG&E NEG guarantee. Neither the PG&E NEG subsidiaries nor PG&E NEG have sufficient funds to make these payments. The requirement to make the payments will remain an obligation of PG&E NEG that would survive the transfer of the projects.

Further, as a result of the La Paloma and Lake Road subsidiaries' failure to make required payments under the interest rate hedge contracts entered into by them, the counterparties to such interest rate hedge contracts have terminated the contracts. Settlement amounts due from the Lake Road and La Paloma project subsidiaries in connection with such terminated contracts are, in the aggregate, approximately $61 million for Lake Road and $79 million for La Paloma.

PG&E GTN Senior Unsecured Notes, Debentures and Medium-Term Notes

On May 31, 1995, PG&E GTN completed the sale of $400 million of debt securities through a $700 million shelf registration. PG&E GTN issued $250 million of 7.10 percent 10-year senior unsecured notes due June 1, 2005, and $150 million of 7.80 percent 30-year senior unsecured debentures due June 1, 2025. The 10-year notes were issued at a discount to yield 7.11 percent and the 30-year debentures were issued at a discount to yield 7.95 percent. At December 31, 2002, the unamortized debt discount balance for the notes and debentures were $0.1 million and $2.0 million, respectively. The 30-year debentures are callable after June 1, 2005, at the option of GTN. Both the senior unsecured notes and the senior unsecured debentures were downgraded during 2002 to a credit rating of CCC from Standard and Poor's and B1 from Moody's Investors Service.

On June 6, 2002, PG&E GTN issued $100 million of 6.62 percent Senior Notes due June 6, 2012. Proceeds were used to repay $90 million of debt on its revolving credit facility, and the balance retained to meet general corporate needs.

In addition, during 1995, $70 million of medium-term notes were issued at face values ranging from $1 million to $17 million. As at January 31, 2003 the medium-term notes carry a credit rating of CCC from Standard and Poor's and B1 from Moody's Investors Service. Medium-term notes totalling $33 million in 2002

and $31 million in 2001 matured and were accordingly extinguished. The remaining notes mature during 2003 and have an average interest rate of 6.96 percent.

Plains End Construction Facility In September 2001, PG&E NEG established a facility for $69.4 million. The debt facility was used to fund the balance of construction costs for the Plains End project. The facility expires upon the earlier of five years after commercial operations have been declared or September 2007. The average weighted interest rate on the amount outstanding is approximately 5.17 percent.

Other long-term debt consists of non-recourse project financing associated with unregulated generating facilities, premiums, and other loans.

Certain credit agreements contain, among other restrictions, customary affirmative covenants, representations and warranties and have cross-default provisions with respect to PG&E NEG's other obligations. The credit agreements also contain certain negative covenants including restrictions on the following: consolidations, mergers, sales of assets and investments; certain liens on the PG&E NEG's property or assets; incurrence of indebtedness; entering into agreements limiting the right of any subsidiary of PG&E NEG to make payments to its shareholders; and certain transactions with affiliates. Certain credit agreements also require that PG&E NEG maintain a minimum ratio of cash flow available for fixed charges to fixed charges and a maximum ratio of funded indebtedness to total capitalization.

Letters of Credit

In addition to outstanding balances under the above credit facilities PG&E NEG has commitments available under these facilities and other facilities to issue letters of credit.

The following table lists the various facilities that have the capacity to issue letters of credit:

(in millions) Borrower	Maturity	Letter of Credit Capacity	Letter of Credit Outstanding December 31, 2002
PG&E NEG	8/03	$ 231	$ 231
USGenNE	8/03	25	13
PG&E Gen	12/04	7	7
PG&E ET	9/03	19	19
PG&E ET	11/03	35	34

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NOTE 4: DEBT FINANCING

Debt in Default and Long-Term Debt

Debt in default and long-term debt that matures in one year or more from the date of issuance consisted of the following:

(in millions)	Balance at December 31, 2002	2001
Debt in Default: [1]		
PG&E NEG credit facilities in default		
Revolving credit facilities in default	$ 473	$ 330
PG&E NEG long-term debt in default		
Senior unsecured notes, 10.375%, due 2011	$ 1,000	$ 1,000
Term loans, various, 2002-2003	2,757	1,676
Total long-term debt in default	3,757	2,676
Total Debt in Default	$ 4,230	$ 3,006
Long-Term Debt:		
PG&E Corporation		
Lehman Loans due 2006, variable	$ 720	$
9.50% Convertible Subordinated Notes	280	
General Electric and Lehman Loans due in 2003, variable		1,000
Discount	(24)	(96)
Total long-term debt, net of current portion	976	904
Utility		
First and refunding mortgage bonds:		
Maturity — Interest Rates		
2003-2005 — 5.875% to 6.250%	880	1,214

(in millions)	Balance at December 31,	
2006-2010 6.35% to 6.625%	85	85
2011-2026 5.85% to 8.80%	2,079	2,079
Principal amounts outstanding	3,044	3,378
Unamortized discount net of premium	(24)	(26)
Total mortgage bonds	3,020	3,352
Less: current portion	281	333
Total long-term debt, net of current portion	2,739	3,019
PG&E NEG		
Senior unsecured notes, 7.10%, due 2005	250	250
Senior unsecured debentures, 7.80%, due 2025	150	150
Senior unsecured notes, 6.62%, due 2012	100	
Medium-term notes, 6.83% to 6.96%, thru 2003	6	39
Term loans, various, 2006	56	123
Amount outstanding under credit facilities	133	160
Other long-term debts	27	24
Sub-total	722	746
Less: current portion	17	48
Amount related to liabilities of Operations held for sale, current	75	75
Total long-term debt, net of current portion	630	623
Total Long-Term Debt	$ 4,345	$ 4,546
Long-Term Debt Subject to Compromise:		
Utility		
Senior notes, 9.63%, due 2005	680	680
Pollution control loan agreements, variable rates, due 2016-2026	614	614
Pollution control loan agreement, 5.35% fixed rate, due 2016	200	200
Unsecured medium-term notes, 5.81% to 8.45%, due 2003-2014	287	287
Deferrable interest subordinated debentures, 7.9%, due 2025	300	
Other Utility long-term debt	19	20
Total Long-Term Debt Subject to Compromise	$ 2,100	$ 1,801

(1) Certain PG&E NEG long-term debt as of December 31, 2001 has been shown in the above schedule as debt in default above for comparative purposes. This long-term debt was not in default during 2001.

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PG&E Corporation

PG&E Corporation entered in a credit agreement (Original Credit Agreement) with General Electric Capital Corporation (GECC) and Lehman Commercial Paper Inc. (LCPI) in 2001. During 2002, PG&E Corporation negotiated new terms to the Original Credit Agreement. In August 2002, PG&E Corporation made a voluntary prepayment of principal and interest totaling $607 million to the GECC portion of the debt. As a result of the prepayment, PG&E Corporation wrote off $83 million of unamortized loan fees and reversed $38 million of unamortized loan discount associated with unvested options, netting to a $45 million charge to interest expense. In relation to the remainder of the loan, PG&E Corporation also recorded $70 million of debt extinguishment losses to interest expense, as a result of new waiver extensions.

On October 18, 2002, PG&E Corporation entered into a Second Amended and Restated Credit Agreement (Credit Agreement) with Lehman Commercial Paper, Inc. (LCPI or, with other parties, the Lenders) with total principal amount of $720 million outstanding at December 31, 2002. The total principal amount includes $420 million previously retained under prior credit arrangements and $300 million representing new loans (New Loans), and collectively referred to as the Loans.

The New Loans were released from escrow to PG&E Corporation on January 17, 2003, concurrent with the payment of a funding fee of $9 million. The Loans are repayable in a single installment on September 2, 2006, unless repaid earlier in accordance with the Credit Agreement.

The interest rate under the Credit Agreement is Eurodollar Rate plus 10 percent, based upon interest periods of one, two, three, or six months, as selected each period by PG&E Corporation. Interest is payable quarterly or at the end of the selected interest period, whichever is shorter. On January 17, 2003, PG&E Corporation paid a first interest payment of $13 million and elected an initial interest period of six months.

In addition, the Credit Agreement provides for Payment-in-Kind (PIK) interest of 4 percent commencing upon receipt of the funds. PIK interest is not paid in cash but rather added to the principal amount of the loan at the start of each interest period.

Except for an option agreement (Option Agreement), granting certain lenders options to purchase common stock of PG&E & NEG, in conjunction with the prior March 1, 2002, Credit Agreement as amended (the Old Credit Agreement), amounts under the Credit Agreement are senior unsubordinated obligations of PG&E Corporation.

On September 3, 2002, General Electric Capital Corporation (GECC) gave notice to PG&E Corporation that it was exercising its right to sell (put) to PG&E Corporation its options representing 1.8 percent of PG&E NEG, which it had acquired in connection with the Old Credit Agreement. Under the terms of the option agreement, PG&E Corporation and GECC entered into an appraisal process to determine the value of the PG&E NEG options. On October 30, 2002, before the completion of the appraisal process, GECC cancelled by giving notice of cancellation of its put notice, which was accepted by PG&E Corporation. GECC no longer has the right to put these options to PG&E Corporation. On February 25, 2003, GECC exercised the options, which otherwise would have expired on March 1, 2003. Similar options representing 1.2 percent of PG&E NEG must also be exercised before March 1, 2003.

Under the Option Agreement discussed above, certain lenders were granted warrants to purchase certain quantities of PG&E NEG shares. These warrants are marked to market on a monthly basis. In the third quarter of 2002, PG&E Corporation recorded other income of $71 million, as a result of the change in market value of the PG&E NEG warrants during that period. As discussed above, the appraisal process to determine the value of PG&E NEG was not completed. If it is determined that PG&E NEG's value is greater than the value currently reflected in the mark-to market accounting, PG&E Corporation would be required to incur a

charge to earnings as a result of the increased valuation.

Security

The Loans are secured by a first priority security interest in the common stock of PG&E NEG and the common stock of the Utility, along with substantially all other assets of PG&E Corporation.

Other Terms

Under the terms of the Credit Agreement, PG&E Corporation is required to make an offer to repay the Loans (including prepayment fees) under various circumstances, which include a change in control of PG&E Corporation and a spin-off of the Utility in connection with a plan of reorganization.

As required by the Credit Agreement, PG&E Corporation retained an interest reserve of $76 million as of December 31, 2002, and upon receipt of the New Loans placed an additional $54 million into such interest reserve.

Restrictions

The Credit Agreement contains limitations, among other restrictions, on the ability of PG&E Corporation and certain of its subsidiaries to grant liens, consolidate, merge, purchase or sell assets, declare or pay dividends, incur indebtedness, or make advances, loans, and investments.

However, PG&E Corporation is permitted to dispose of PG&E NEG assets under certain circumstances. Any proceeds to PG&E Corporation from such permitted sales must be applied to prepay the Loans.

Events of Default and Mandatory Prepayments

The Credit Agreement contains certain events of default, including PG&E Corporation's failure to pay any indebtedness of $100 million or more. Upon an event of default, the Lenders are entitled to accelerate and declare the Loans immediately due and payable.

The Credit Agreement requires mandatory prepayments with the net cash proceeds from incurrence of additional indebtedness, issuance or sale of equity by PG&E Corporation or the Utility, sale of certain assets by PG&E Corporation, the Utility, or PG&E NEG; the receipt of condemnation or insurance proceeds, and distributions or dividends paid to PG&E Corporation or PG&E NEG.

Upon mandatory prepayment, PG&E Corporation must pay a prepayment fee calculated depending upon when the prepayment occurred.

PG&E Corporation Warrants

In connection with the Credit Agreement, PG&E Corporation also issued to the Lenders warrants to purchase 2,658,268 shares of common stock of PG&E Corporation, at an exercise price of $0.01 per share. These warrants expire on September 2, 2007, and are generally exercisable except when by their exercise the holder becomes, and has the intention to remain, the single largest common shareholder.

The fair market value of these warrants was estimated at the date of grant and recorded as a discount to long-term debt. At December 31, 2002, the discount was $24 million, net of accumulated discount amortization of $1 million.

In connection with the prior June 25th Amended and Restated Credit Agreement, PG&E Corporation issued warrants to the lenders to purchase 2,397,541 shares of common stock of PG&E Corporation, at an exercise price of $0.01 per share and with terms similar to the warrants described above. The unamortized discount related to these warrants and other deferred financing costs were charged to interest expense upon the voluntary repayment of $600 million principal and interest of approximately $6.7 million in August 2002.

PG&E Corporation has agreed to provide, following consummation of a plan of reorganization of the Utility, registration rights