PACIFIC GAS & ELECTRIC CO
Form S-3
October 27, 2003

As filed with the Securities and Exchange Commission on October 27, 2003

Registration No. 333-

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form S-3

REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

Pacific Gas and Electric Company

(Exact Name of Registrant as Specified in Its Charter)

California	**77 Beale Street** **P.O. Box 770000** **San Francisco, CA 94177** **(415) 973-7000**	**94-0742640**
(State or Other Jurisdiction of Incorporation or Organization)	*(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant s Principal Executive Offices)*	*(I.R.S. Employer Identification Number)*

Bruce R. Worthington
Senior Vice President and General Counsel
PG&E Corporation
One Market Spear Tower, Suite 2400
San Francisco, CA 94105
(415) 267-7000
(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent for Service)

Approximate date of commencement of proposed sale to the public: From time to time after the effective date of this Registration Statement.

If the only securities being registered on this form are being offered pursuant to dividend or interest reinvestment plans, please check the following box. o

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, other than securities offered only in connection with dividend or interest reinvestment plans, check the following box. þ

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o ______________

If this form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o ______________

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. o

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to Be Registered	Amount to Be Registered	Proposed Maximum Offering Price Per Debt Security	Proposed Maximum Aggregate Offering Price	Amount of Registration Fee
Debt Securities	$9,400,000,000(1)	100%(1)(2)(3)	$9,400,000,000(1)(2)(3)	$760,460

(1) Includes an indeterminate principal amount of debt securities as may from time to time be issued at indeterminate prices; provided that in no event will the aggregate initial price of all debt securities sold under this registration statement exceed $9,400,000,000. If any such debt securities are issued at an original issue discount, then the aggregate initial offering price as so discounted shall not exceed $9,400,000,000, notwithstanding that the stated aggregate principal amount of such debt securities may exceed such amount.

(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(o) under the Securities Act of 1933, as amended. The proposed maximum initial offering price per security will be determined from time to time by the registrant in connection with the issuance of the debt securities.

(3) Exclusive of accrued interest, if any.

The registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until this Registration Statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

The information in this preliminary prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This preliminary prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

PROSPECTUS

Subject to Completion, dated October 27, 2003

$9,400,000,000

Pacific Gas and Electric Company

Debt Securities

Under this prospectus, we may offer and sell from time to time debt securities with an aggregate initial offering price of up to $9,400,000,000 in one or more offerings. This prospectus provides you with a general description of the debt securities that may be offered.

Each time we sell debt securities, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered debt securities. The prospectus supplement also may add, delete, update or change information contained in this prospectus. You should carefully read this prospectus and any applicable prospectus supplement for the specific offering before you invest in any of the debt securities. This prospectus may not be used to sell debt securities unless accompanied by a prospectus supplement.

The debt securities may be sold to or through underwriters, dealers or agents or directly to other purchasers. A prospectus supplement will set forth the names of any underwriters, dealers or agents involved in the sale of the debt securities, the aggregate principal amount of debt securities to be purchased by them and the compensation they will receive.

We were incorporated in California in 1905. Our principal executive offices are located at 77 Beale Street, San Francisco, California 94177, and our telephone number at that location is (415) 973-7000.

Please see Risk Factors beginning on page 1 for a discussion of factors you should consider in connection with a purchase of the debt securities offered by this prospectus.

None of the Securities and Exchange Commission, any state securities commission or any other regulatory body has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

, 2003.

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Unless otherwise indicated, when used in this prospectus, the terms we, our and us refer to Pacific Gas and Electric Company and its subsidiaries, and the term Corp refers to our parent, PG&E Corporation.

In addition, unless otherwise indicated, the disclosure throughout this prospectus assumes that:

the California Public Utilities Commission, or the CPUC, has approved the settlement agreement which was executed by us, Corp and the CPUC on , 2003, and is referred to in this prospectus as the CPUC settlement agreement, as well as the financings and rates contemplated by the CPUC settlement agreement, and that no appeals have been or will be made of these approvals;

our plan of reorganization, which was confirmed by the United States Bankruptcy Court for the Northern District of California, or the bankruptcy court, on , 2003 and is referred to in this prospectus as our plan of reorganization, has not been modified in any material way since the date of confirmation, and the confirmation order is final and nonappealable; and

all the other conditions to the effectiveness of our plan of reorganization have been satisfied or are reasonably anticipated to be satisfied within 90 days of the closing date of the initial offering of debt securities under this prospectus.

UNITS OF MEASUREMENT

1 Kilowatt (kW)	=	One thousand watts
1 Kilowatt-Hour (kWh)	=	One kilowatt continuously for one hour
1 Megawatt (MW)	=	One thousand kilowatts
1 Megawatt-Hour (MWh)	=	One megawatt continuously for one hour
1 Gigawatt (GW)	=	One million kilowatts
1 Gigawatt-Hour (GWh)	=	One gigawatt continuously for one hour
1 Kilovolt (kV)	=	One thousand volts
1 MVA	=	One megavolt ampere
1 Mcf	=	One thousand cubic feet
1 MMcf	=	One million cubic feet
1 Bcf	=	One billion cubic feet
1 Decatherm (Dth)	=	Ten therms, also equivalent to one million British thermal units
1 MDth	=	One thousand decatherms

ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that we filed with the Securities and Exchange Commission, or the SEC, using a shelf registration process. Under this shelf registration process, we may from time to time sell debt securities with an aggregate initial offering price of up to $9,400,000,000 in one or more offerings.

This prospectus provides you with only a general description of the debt securities that we may offer. This prospectus does not contain all of the information set forth in the registration statement of which this prospectus is a part, as permitted by the rules and regulations of the SEC. For additional information regarding us and the offered debt securities, please refer to the registration statement of which this prospectus is a part. Each time we sell debt securities, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered securities. The prospectus supplement also may add, delete, update or change information contained in this prospectus. You should rely only on the information in the applicable prospectus supplement if this prospectus and the applicable prospectus supplement are inconsistent. Before purchasing any debt securities, you should carefully read both this prospectus and the applicable prospectus supplement, together with the additional information described under the section of this prospectus titled Where You Can Find More Information.

You should rely only on the information contained or incorporated by reference in this prospectus and in any applicable prospectus supplement. We have not authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. Neither we nor any underwriter, dealer or agent will make an offer to sell the debt securities in any jurisdiction where the offer or sale is not permitted. You should assume that the information in this prospectus and any applicable prospectus supplement is accurate only as of the dates on their covers. Our business, financial condition, results of operations and prospects may have changed since those dates.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus, the documents incorporated by reference in this prospectus and any applicable prospectus supplement contain various forward-looking statements. These forward-looking statements can be identified by the use of words such as assume, expect, intend, plan, project, believe, estimate, predict, anticipate, may, might, will, should, could, goal, potential and similar expressions. W forward-looking statements on our current expectations and projections about future events, our assumptions regarding these events and our knowledge of facts at the time the statements are made. These forward-looking statements are subject to various risks and uncertainties that may be outside our control, and our actual results could differ materially from our projected results. These risks and uncertainties include, among other things:

governmental and regulatory policies and legislative, regulatory or ratemaking actions generally, including those of the California legislature, the U.S. Congress, the CPUC and the Federal Energy Regulatory Commission, or the FERC, as to allowed rates of return, industry and rate structure, price mitigation or bid caps on wholesale electricity prices, timely recovery of our investments and costs, the disposition of utility assets and facilities, treatment of affiliate contracts and relationships, operation and construction of facilities, and enforcement of or compliance with applicable rules, tariffs, licenses and orders;

our ability to manage over time our residual net open position, which is the portion of our electricity customers demand not satisfied by electricity from our generation facilities, our electricity purchase contracts or California Department of Water Resources, or DWR, electricity contracts allocated to our customers;

the inability of various counterparties to perform their supply obligations under their electricity purchase contracts with us or with the DWR, thereby increasing the risk that we will need to buy additional electricity;

weather, storms, earthquakes, fires, other natural disasters, explosions, accidents, mechanical breakdowns and other events or perils that affect demand, result in power outages, reduce generating output or damage our assets or operations or those of third parties on which we rely;

unanticipated changes in our operating expenses and capital expenditures;

the level and volatility of wholesale electricity and natural gas prices and our ability to manage and respond to this volatility successfully;

the effect of compliance with existing and future environmental laws, regulations and policies;

increased competition as a result of the takeover by condemnation, or municipalization, of our distribution assets, self-generation by our customers and other forms of competition that may result in stranded investment capital, decreased customer growth, loss of customer load and additional barriers to cost recovery;

unanticipated population growth or decline, changes in market demand and demographic patterns, and general economic and financial market conditions, including unanticipated changes in interest or inflation rates;

the extent to which the cities and counties in our service territory become community choice aggregators and the extent to which our distribution customers can switch between purchasing electricity from us or from alternate energy service providers and the attendant risks from any material loss or gain of customers;

the operation and decommissioning of our Diablo Canyon nuclear power plant, which expose us to potentially significant environmental and capital expenditure risks, and, to the extent we are unable to increase our spent fuel storage capacity by 2007 or find an alternative depository, the risk that we may be required to close our Diablo Canyon power plant and purchase electricity from more expensive sources;

acts of terrorism;

- the outcome of pending litigation, rate cases and other regulatory proceedings;
- significant changes in our relationship with our employees, the availability of qualified personnel and potential adverse effects if labor disputes were to occur;
- actions of rating agencies; and
- new accounting pronouncements, including significant changes in accounting policies material to us.

For additional factors that could affect the validity of our forward-looking statements, you should read the section of this prospectus titled Risk Factors.

You should read this prospectus and any applicable prospectus supplements, the documents that we have filed as exhibits to the registration statement of which this prospectus is a part and the documents that we refer to under the section of this prospectus titled Where You Can Find More Information completely and with the understanding that our actual future results could be materially different from what we currently expect. We qualify all our forward-looking statements by these cautionary statements. These forward-looking statements speak only as of the date of this prospectus. Except as required by applicable laws or regulations, we do not undertake any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

RISK FACTORS

You should carefully consider the risks and uncertainties described below and the other information contained in this prospectus or any applicable prospectus supplement or incorporated by reference in this prospectus before you decide whether to purchase the debt securities. The risks and uncertainties described below are not the only ones we may face. The following risks, together with additional risks and uncertainties not currently known to us or that we may currently deem immaterial, could impair our business operations and ultimately affect our ability to make payments on the debt securities.

Risks Related to Us

Our financial viability depends upon our ability to recover our costs in a timely manner from our customers through regulated rates and otherwise execute our business strategy.

We are a regulated entity subject to CPUC jurisdiction in almost all aspects of our business, including the rates, terms and conditions of our services, procurement of electricity and natural gas for our customers, issuance of securities, dispositions of utility assets and facilities and aspects of the siting and operation of our electricity and natural gas distribution systems. Executing our business strategy depends on periodic CPUC approvals of these and related matters. Our ongoing financial viability depends on our ability to recover from our customers in a timely manner all our costs, including the costs of electricity and natural gas purchased by us for our customers, in our CPUC-approved rates and our ability to pass through to our customers in rates our FERC-authorized revenue requirements. During the California energy crisis, the high price we had to pay for electricity on the wholesale market, coupled with our inability to fully recover our costs in retail rates, caused our costs to significantly exceed our revenues and ultimately caused us to file a petition under Chapter 11 of the United States Bankruptcy Code, or Chapter 11. Even though the CPUC settlement agreement contemplates that the CPUC will give us the opportunity to recover our reasonable and prudent future costs in our rates, there can be no assurance that the CPUC will find that all of our costs are reasonable and prudent or will not otherwise take or fail to take actions to our detriment. In addition, there can be no assurance that the bankruptcy court or other courts will implement and enforce the terms of the CPUC settlement agreement and our plan of reorganization in a manner that would produce the economic results that we intend or anticipate. Further, there can be no assurance that FERC-authorized tariffs will be adequate to cover the related costs. If we are unable to recover any material amount of our costs through our rates in a timely manner, our financial condition and results of operations would be materially adversely affected.

We may be unable to purchase electricity in the wholesale market or to increase our generating capacity in a manner that the CPUC will find reasonable or in amounts sufficient to satisfy our residual net open position.

The electricity we generate and have under contract, combined with the electricity furnished under the DWR electricity contracts allocated to our customers, or the DWR allocated contracts, may not be sufficient to satisfy our customer s electricity demand in the future. Our residual net open position will increase over time for a number of reasons, including:

- periodic expirations of our existing electricity purchase contracts;
- periodic expirations or other terminations of the DWR allocated contracts; and
- increases in our customers electricity demands due to customer and economic growth or other factors.

In addition, unexpected outages at our Diablo Canyon power plant or any of our other significant generation facilities, or a failure to perform by any of the counterparties to our electricity purchase contracts or the DWR allocated contracts, would immediately increase our residual net open position.

As existing electricity purchase contracts expire, sources of electricity otherwise become unavailable or demand increases, we will purchase electricity in the wholesale market. These purchases will be made under contracts priced at the time of execution or, if made in the spot market, at the then-current market price of wholesale electricity. There can be no assurance that sufficient replacement electricity will be available at prices and on terms that the CPUC finds reasonable, or at all. Our financial condition and results of operations would be materially adversely affected if we were unable to purchase electricity in the wholesale market on terms the CPUC finds reasonable or in quantities sufficient to satisfy our residual net open position.

Alternatively, the CPUC may require us or we may elect to satisfy all or a part of our residual net open position by developing or acquiring additional generation facilities. This could result in significant additional capital expenditures or other costs and may require us to issue additional debt, which we may not be able to issue on reasonable terms, or at all. In addition, if we are not able to recover a material part of the cost of developing or acquiring additional generation facilities in our rates in a timely manner, our financial condition and results of operations would be materially adversely affected.

Our financial condition and results of operations could be materially adversely affected if we are unable to successfully manage the risks inherent in operating our facilities.

We own and operate extensive electricity and natural gas facilities that are interconnected to the U.S. western electricity grid and numerous interstate and continental pipelines. The operation of our facilities and the facilities of third parties on which we rely involves numerous risks, including:

- operating limitations that may be imposed by environmental or other regulatory requirements;
- imposition of stringent operational performance standards by agencies with regulatory oversight of our facilities;
- environmental and personal injury liabilities;
- fuel interruptions;
- blackouts;
- labor disputes;
- weather, storms, earthquakes, fires, floods or other natural disasters; and
- explosions, accidents, mechanical breakdowns and other events or perils that affect demand, result in power outages, reduce generating output or cause damage to our assets or operations or those of third parties on which we rely.

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

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

In the recent past, the commodity markets for electricity and natural gas have been highly volatile and subject to substantial price fluctuations. A variety of factors may contribute to commodity market volatility, including:

- weather;
- supply and demand;
- the availability of competitively priced alternative energy sources;
- the level of production of natural gas;
- the price of other fuels that are used to produce electricity, including crude oil and coal;

the transparency, efficiency, integrity and liquidity of regional energy markets affecting California;

electric transmission or natural gas transportation capacity constraints;

federal, state and local energy and environmental regulation and legislation; and

natural disasters, war, terrorism and other catastrophic events.

These factors are largely outside our control. If wholesale electricity or natural gas prices increase significantly, public pressure or other regulatory or governmental influences could constrain the willingness of the CPUC to authorize timely recovery of our costs. Moreover, the volatility of commodity markets could cause us to apply more frequently to the CPUC for authority to timely recover our costs in rates. If we are unable to recover any material amount of our costs in our rates in a timely manner, our financial condition and results of operations would be materially adversely affected.

Our operations are subject to extensive environmental laws, and changes in, or liabilities under, these laws could adversely affect our financial condition and results of operations.

Our operations are subject to extensive federal, state and local environmental laws. Complying with these environmental laws has in the past required significant expenditures for hazardous substance removal, environmental remediation, environmental monitoring and pollution control equipment at our facilities and the surrounding areas, as well as for related fees and permits. Moreover, compliance in the future may require significant expenditures relating to electric and magnetic fields, or EMFs. Due to the potential for imposition of stricter standards and greater regulation in the future and the possibility that other potentially responsible parties may not be financially able to contribute to these costs, our environmental compliance and remediation costs could increase and the timing of our capital expenditures in the future may accelerate. If we are unable to recover the costs of complying with environmental laws in our rates in a timely manner, our financial condition and results of operations could be materially adversely affected. In addition, in the event we must pay materially more than the amount that we currently have reserved on our balance sheet to satisfy our environmental remediation obligations and we are unable to recover these costs from insurance or through rates in a timely manner, our financial condition and results of operations would be materially adversely affected.

We face the risk of unrecoverable costs if our customers obtain distribution and transportation services from other providers as a result of municipalization or other forms of competition.

Our customers could bypass our distribution and transportation system by obtaining service from other sources. Forms of bypass of our electricity distribution system include the construction of duplicate distribution facilities to serve specific existing or new customers, the municipalization of our distribution facilities by local governments or districts, self-generation by our customers and other forms of competition. Bypass of our system may result in stranded investment capital, loss of customer growth or additional barriers to cost recovery. Our natural gas transportation facilities also are at risk of being bypassed by customers who build pipeline connections that bypass our natural gas transportation system. As customers and local public officials explore their energy options in light of the recent California energy crisis, these bypass risks may be increasing and may increase further if our rates exceed the cost of other available alternatives. In addition, technological changes could result in the development of economically attractive alternatives to purchasing electricity through our distribution facilities. We cannot currently predict the impact of these actions and developments on our business, although one possible outcome is a decline in the demand for the services that we provide, which would result in a corresponding decline in our revenues.

If the number of our customers declines due to bypass, technological changes or other forms of competition, and our rates are not adjusted in a timely manner to allow us to fully recover our investment and electricity procurement costs, our financial condition and results of operations would be materially adversely affected.

We face the risk of unrecoverable costs resulting from changes in the number of customers in our service territory for whom we purchase electricity.

As part of California s electricity industry restructuring, our customers were given the choice of either continuing to receive electricity procurement, transmission and distribution services, or bundled service, from us, or electing to purchase electricity from alternate energy service providers, and to thus become direct access customers. The CPUC suspended the right of end-user customers to become direct access customers on September 20, 2001, although customers that were then direct access customers have been allowed to remain on direct access. Separately, the CPUC has instituted a rulemaking implementing California s Assembly Bill 117, or AB 117, permitting California cities and counties to purchase and sell electricity for their residents once they have registered as community choice aggregators. We would continue to provide distribution, metering and billing services to the community choice aggregators customers and would be those customers electricity provider of last resort. However, once registration has occurred, each community choice aggregator would procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from us.

If we lose a material number of customers as a result of cities and counties electing to become community choice aggregators or the CPUC allowing resumption of direct access, our electricity purchase contracts could obligate us to purchase more electricity than our remaining customers require, the excess of which we would have to sell in the wholesale spot market, possibly at a loss. Further, if we must provide electricity to customers discontinuing direct access or who elect to leave a community choice aggregator, we may be required to make unanticipated purchases of additional electricity at higher prices.

If we have excess electricity or we must make unplanned purchases of electricity as a result of the actions of community choice aggregators customers or direct access customers, and the CPUC fails to adjust our rates to reflect the impact of these actions, our financial condition and results of operations could be materially adversely affected.

The operation and decommissioning of our nuclear power plants expose us to potentially significant liabilities and capital expenditures.

The operation and decommissioning of our nuclear power plants expose us to potentially significant liabilities and capital expenditures, including those arising from the storage, handling and disposal of radioactive materials and uncertainties related to the regulatory, technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. We maintain decommissioning trusts and external insurance coverage to reduce our financial exposure to these risks. However, the costs or damages we may incur in connection with the operation and decommissioning of nuclear power plants could exceed the amount of our insurance coverage and other amounts set aside for these potential liabilities. In addition, as an operator of two operating nuclear reactor units, we may be required under federal law to pay up to $201.2 million of liabilities arising out of each nuclear incident occurring not only at our Diablo Canyon power plant but at any other nuclear power plant in the United States. If we cannot recover any material amount of these excess costs or damages in our rates in a timely manner, our financial condition and results of operations would be materially adversely affected.

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

If we fail to increase the spent fuel storage capacity at our Diablo Canyon nuclear power plant by the spring of 2007 and there are no other available alternatives, we would be forced to close it and would therefore be required to purchase electricity from more expensive sources.

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

Acts of terrorism could materially adversely affect our financial condition and results of operations.

Our facilities, including our operating and retired nuclear facilities and the facilities of third parties on which we rely, could be targets of terrorist activities. A terrorist attack on these facilities could result in a full or partial disruption of our ability to generate, transmit, transport or distribute electricity or natural gas or cause environmental repercussions. Any operational disruption or environmental repercussions could result in a significant decrease in our revenues or significant reconstruction or remediation costs, which could materially adversely affect our financial condition and results of operations.

Adverse judgments or settlements in the chromium litigation cases could materially adversely affect our financial condition and results of operations.

We are a named defendant in 14 civil actions currently pending in California courts relating to alleged chromium contamination. The chromium litigation complaints allege personal injuries, wrongful death and loss of consortium and seek unspecified compensatory and punitive damages based on claims arising from alleged exposure to chromium contamination in the vicinity of three of our natural gas compressor stations. If we pay a material amount in excess of the amount that we currently have reserved on our balance sheet to satisfy chromium-related liabilities and costs, our financial condition and results of operations could be materially adversely affected.

Changes in, or liabilities under, our permits, authorizations or licenses could adversely affect our financial condition and results of operations.

Our operations are subject to a number of governmental permits, authorizations and licenses. These permits, authorizations and licenses may be revoked or modified by the agency that granted them if facts develop that differ significantly from the facts assumed when they were issued. Furthermore, discharge permits and other approvals and licenses are granted for a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. For example, we currently have eight hydroelectric generation facilities undergoing FERC license renewal. In connection with a license renewal, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the licensed hydroelectric generation facility. If we are unable to obtain, renew or comply with these governmental permits, authorizations or licenses, or we are unable to recover any increased costs of complying with additional license requirements or any other associated costs in a timely manner, our financial condition and results of operations could be materially adversely affected.

Risks Related to the Debt Securities

After giving effect to our plan of reorganization, we will have a significant amount of debt, and the agreements governing that indebtedness will allow us to incur additional debt in the future, which could adversely affect our ability to make payments on the debt securities.

After giving effect to our plan of reorganization (including the expected issuance of debt securities offered by this prospectus in connection with our plan of reorganization, borrowings under our contemplated credit facilities and payments to holders of allowed claims and equity interests), we currently expect to have approximately $9.4 billion in total debt outstanding on the effective date of our plan of reorganization (excluding rate reduction bonds). In addition, the indentures governing the debt securities offered by this prospectus and the terms of the contemplated credit facilities will allow us to incur additional indebtedness. Our level of debt could have important consequences to holders of the debt securities. For example, additional debt could require us to dedicate a greater portion of our cash flow to paying interest expense and debt amortization, which would reduce the funds available to us for our operations and capital expenditures, limit our ability to obtain additional financing for capital expenditures, working capital or for other purposes and increase our vulnerability to adverse economic and industry conditions.

Our ability to make scheduled payments of principal and interest on the debt securities and to satisfy other debt obligations will depend on the cash flow from our operations and other available sources of liquidity, such as equity offerings or additional debt financings. We can provide no assurance that these sources of liquidity will be available to us if and when needed or on terms acceptable to us. The level of indebtedness we expect to have outstanding after giving effect to our plan of reorganization and the establishment of the credit facilities, as well as future indebtedness levels, could adversely affect our ability to make payments of principal and interest on the debt securities.

There is no existing market for the debt securities, and we cannot assure you that an active trading market will develop.

There is no existing market for the debt securities and we do not intend to apply for listing of the debt securities on any securities exchange or any automated quotation system. There can be no assurance as to the liquidity of any market that may develop for the debt securities, the ability of the holders of the debt securities to sell their debt securities or the price at which holders of the debt securities will be able to sell their debt securities. Future trading prices of the debt securities will depend on many factors, including prevailing interest rates, our financial condition and results of operations, the then-current ratings assigned to the debt securities and the market for similar securities.

If a particular offering of debt securities is sold to or through underwriters, the underwriters may attempt to make a market in the debt securities. However, the underwriters would not be obligated to do so and they could terminate any market-making activity at any time without notice. If a market for any of the debt securities does not develop, holders of those debt securities may be unable to resell them for an extended period of time and those debt securities may not be readily accepted as collateral for loans.

The terms of our debt instruments could restrict our flexibility and limit our ability to make payments on the debt securities.

Some of the pollution control bond-related agreements that we may reinstate as part of our plan of reorganization and both forms of indenture governing the debt securities offered by this prospectus contain restrictions on the amount and type of secured indebtedness that we may incur. In addition, if we issue unsecured debt securities under this prospectus in connection with our plan of reorganization, the existing mortgage indenture that we will amend and restate contains, and will continue to contain, an interest coverage ratio that we must satisfy before we can issue future mortgage bonds. We expect that the contemplated credit facilities will contain financial and operational covenants. In addition, the instruments governing future indebtedness that we may incur could also contain financial covenants and other restrictions on us. These covenants and restrictions could limit our flexibility and limit our ability to borrow additional funds to finance operations and to make principal and interest payments on the debt securities. In addition, failure to comply with these covenants could result in an event of default under the terms of the agreements that, if not cured or waived, could result in the indebtedness becoming due and payable. The effect of these covenants, or our failure to comply with them, could materially adversely affect our business, financial condition, results of operations and our ability to satisfy our obligations under the debt securities.

USE OF PROCEEDS

Each prospectus supplement will describe the uses of the proceeds from the issuance of the debt securities offered by that prospectus supplement.

SELECTED CONSOLIDATED FINANCIAL DATA

The following table presents our selected consolidated financial data for the years ended December 31, 2002, 2001, 2000, 1999 and 1998 and the six months ended June 30, 2003 and 2002. We derived the selected consolidated financial data for the years ended December 31, 2002, 2001 and 2000 from our audited consolidated financial statements included in this prospectus and the selected consolidated financial data for the years ended December 31, 1999 and 1998 from our audited consolidated financial statements not included in this prospectus. We derived the selected consolidated financial data for the six months ended June 30, 2003 and 2002 from our unaudited interim consolidated financial statements included in this prospectus. In the opinion of our management, the interim financial statements include all normal recurring adjustments necessary to present fairly the information required to be set forth in those financial statements. However, our operating results for interim periods are not necessarily indicative of a full year s operations. In addition, our historical operating results are not necessarily indicative of future operations. The data below should be read in conjunction with, and is qualified in its entirety by reference to, our consolidated financial statements, the notes to those financial statements and the section of this prospectus titled Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Six Months Ended June 30,		Year Ended December 31,				
	2003	2002	2002	2001	2000	1999	1998
			(dollars in millions)				
Consolidated Statements of Operations Data:							
Operating revenues:							
Electric	$3,299	$3,971	$ 8,178	$ 7,326	$ 6,854	$7,232	$7,191
Natural gas	1,498	1,196	2,336	3,136	2,783	1,996	1,733
Total operating revenues	4,797	5,167	10,514	10,462	9,637	9,228	8,924
Operating expenses:							
Depreciation, amortization and decommissioning	605	565	1,193	896	3,511	1,564	1,438
Other operating expenses	3,388	2,295	5,408	7,088	11,327	5,671	5,610
Total operating expenses	3,993	2,860	6,601	7,984	14,838	7,235	7,048
Operating income (loss)(1)	804	2,307	3,913	2,478	(5,201)	1,993	1,876
Interest expense(2)	(444)	(546)	(988)	(974)	(619)	(593)	(621)
Other income	38	35	72	107	183	36	103
Income tax (provision) benefit	(125)	(731)	(1,178)	(596)	2,154	(648)	(629)
Net income (loss) from continuing operations(1)	$ 273	$1,065	$ 1,819	$ 1,015	$ (3,483)	$ 788	$ 729
Other Data (unaudited):							
Ratio of earnings to fixed charges(3)	1.87x	4.16x	3.91x	2.58x	x(4)	3.25x	3.02x
EBITDA(5)	$1,447	$2,907	$ 5,178	$ 3,481	$ (1,507)	$3,593	$3,417

	June 30,	December 31,				
	2003	2002	2001	2000	1999	1998
		(in millions)				
Consolidated Balance Sheet Data:						
Cash and cash equivalents	$ 3,700	$ 3,343	$ 4,341	$ 1,344	$ 101	$ 90
Restricted cash	234	150	53	50		
Working capital	3,395	3,382	4,291	(6,192)	(1,603)	(999)
Net property, plant and equipment	15,913	13,957	13,357	13,001	12,718	12,872
Total assets	26,013	24,551	25,269	21,988	21,470	22,950

Debt, classified as current	881	571	623	5,743	1,204	1,218
Long-term debt	2,429	2,739	3,019	3,342	4,877	5,444
Rate reduction bonds (excluding current portion)	1,019	1,160	1,450	1,740	2,031	2,321
Liabilities subject to compromise	9,456	9,391	11,384			
Preferred securities with mandatory redemption provisions	137	137	437	437	437	437
Shareholders equity	4,394	4,194	2,398	1,410	5,771	6,348

(1) Operating income (loss) and net income (loss) from continuing operations reflect the write-off of generation-related regulatory assets and under-collected electricity purchase costs in 2000. For more information, see the section of this prospectus titled Management s Discussion and Analysis of Financial Condition and Results of Operations and the notes to our consolidated financial statements.

(2) Interest expense includes non-contractual interest expense of $67 million and $103 million for the six months ended June 30, 2003 and 2002, respectively, and $149 million and $164 million for the years ended December 31, 2002 and 2001, respectively.

(3) For the purpose of computing ratios of earnings to fixed charges, earnings represent net income adjusted for income taxes and fixed charges. Fixed charges include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases and the amount of earnings required to cover the preferred security distribution requirements of our wholly owned trust.

(4) The ratio of earnings to fixed charges indicates a deficiency of less than one-to-one coverage of $5.6 billion.

(5) EBITDA is defined as income before provision for income taxes, interest expense and depreciation, amortization and decommissioning. We believe that EBITDA provides one of the best comparative measures for operating performance and is a standard measure commonly reported and widely used by analysts, investors and other parties as an indication of our ability to service our debt. EBITDA is not intended to represent net cash provided by operating activities and should not be considered as an alternative to net income as an indicator of operating performance or to cash flows as a measure of liquidity. EBITDA is not a measurement of operating performance computed in accordance with accounting principles generally accepted in the United States of America, or GAAP, and it should not be considered a substitute for operating income or cash flows from operations prepared in conformity with GAAP. Our method of computation may or may not be comparable to other similarly titled measures used by other companies.

EBITDA is calculated from net income (loss) from continuing operations (which we believe to be the most directly comparable financial measures calculated in accordance with GAAP). Set forth below is a reconciliation of EBITDA to both net income (loss) from continuing operations and net cash provided by operating activities.

	Six Months Ended June 30,		Year Ended December 31,				
	2003	**2002**	**2002**	**2001**	**2000**	**1999**	**1998**
				(in millions)			
Net income (loss) from continuing operations	$ 273	$ 1,065	$ 1,819	$ 1,015	$ (3,483)	$ 788	$ 729
Adjustments to reconcile EBITDA to net income (loss) from continuing operations:							
Depreciation, amortization and decommissioning	605	565	1,193	896	3,511	1,564	1,438
Interest expense	444	546	988	974	619	593	621
Income tax provision (benefit)	125	731	1,178	596	(2,154)	648	629
EBITDA	$ 1,447	$ 2,907	$ 5,178	$ 3,481	$ (1,507)	$ 3,593	$ 3,417
Adjustments to reconcile EBITDA to net cash provided by operating activities:							
Cash paid for interest	(341)	(683)	(1,105)	(361)	(587)	(531)	(600)
Cash paid for taxes	32	(353)	(1,186)	556		(1,001)	(1,115)
Deferral of electric procurement costs					(6,465)		
Provision for loss on generation-related regulatory assets and undercollected purchased power costs					6,939		
Reversal of ISO accrual		(970)	(970)				
Change in deferred charges and other non-current liabilities	284	363	102	(954)	480	101	31
Change in working capital (other than income taxes payable)	(59)	161	363	2,379	2,263	464	2,061
Payments authorized by bankruptcy court	(62)	(947)	(1,442)	(16)			
Other, net	(97)	152	194	(320)	(568)	(430)	(58)
Net cash provided by operating activities	$ 1,204	$ 630	$ 1,134	$ 4,765	$ 555	$ 2,196	$ 3,736

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS

You should read the following discussion in conjunction with the sections of this prospectus titled Special Note Regarding Forward-Looking Statements, Risk Factors, Selected Consolidated Financial Data and the financial statements and related notes included elsewhere in this prospectus.

Overview

We are a leading vertically integrated electricity and natural gas utility. We operate in northern and central California and are engaged in the businesses of electricity generation, electric transmission, natural gas transportation and storage, and electricity and natural gas distribution.

We own and operate an extensive hydroelectric system, the Diablo Canyon nuclear power plant and two fossil fuel-fired plants. The electricity generated from these facilities, along with electricity furnished under electricity purchase contracts, or as needed from the spot market, is used to satisfy our customers electricity demands. The DWR also provides electricity to us for distribution to our customers under the DWR allocated contracts. We purchase natural gas for our core customers, comprised of small commercial and residential customers, and transport this natural gas along with natural gas purchased principally by our large commercial and industrial customers directly from suppliers through our natural gas transportation and distribution system. We have arrangements with interstate natural gas transportation companies to ship the natural gas purchased for our core customers from producing areas (principally in western Canada and the southwest United States) to our pipeline facilities in California.

The electricity and natural gas industries have undergone various stages of deregulation since the mid-1990s. Natural gas deregulation preceded electricity deregulation and the regulatory framework for natural gas has been relatively stable in recent years. In 1996, the State of California adopted legislation restructuring the electricity markets in California and, in 1998, the CPUC implemented electricity industry restructuring.

Beginning in May 2000, wholesale electricity prices began to increase. Since our retail electricity rates remained frozen, we financed the higher costs of wholesale electricity by issuing debt and drawing on our credit facilities. Our inability to recover our electricity purchase costs from customers ultimately resulted in billions of dollars in defaulted debt and unpaid bills and caused us to file a voluntary petition for relief under Chapter 11 on April 6, 2001. Pursuant to Chapter 11, we have retained control of our assets and are authorized to operate as a debtor-in-possession while we are subject to the jurisdiction of the bankruptcy court.

Our plan of reorganization was confirmed by the bankruptcy court on . We expect to emerge from bankruptcy before the end of the first quarter of 2004. Our plan of reorganization generally provides for payment in full of all allowed creditor claims (except for the claims of holders of pollution control bond-related obligations that will be reinstated) plus applicable interest on claims in certain classes and all cumulative dividends in arrears and mandatory sinking fund payments associated with our preferred stock. After giving effect to our plan of reorganization (including the expected issuance of debt securities offered by this prospectus in connection with our plan of reorganization, borrowings under our contemplated credit facilities and payments to holders of allowed claims and equity interests), we currently expect to have approximately $9.4 billion in total debt outstanding on the effective date of our plan of reorganization (excluding rate reduction bonds). Under our plan of reorganization, we would remain a vertically integrated electricity and natural gas utility primarily regulated by the CPUC. For more information regarding our plan of reorganization, see the section of this prospectus titled Description of Our Plan of Reorganization.

Our 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. In addition, these financial statements apply principles used by rate regulated companies.

In this Management s Discussion and Analysis of Financial Condition and Results of Operations, we first discuss our historical results of operations. Under Liquidity and Capital Resources below, we discuss our current cash position and our historical cash flows. We also discuss our commitments and contingencies and other matters that are relevant to understanding our financial condition and results of operations.

Critical Accounting Policies

The preparation of consolidated financial statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies due, in part, to their complexity and because their application is relevant and material to our financial position and results of operations, and because these policies require the use of material judgments and estimates. These policies and their key characteristics are outlined below.

Unbilled and Surcharge Revenues

We record revenue 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 or energy delivered with recent historical usage and rate patterns.

Since the CPUC authorized the collection of surcharge revenues in January, March and May 2001, we have collected generation-related revenues in excess of generation-related costs of approximately $2.0 billion (after-tax). We have not provided reserves for potential refunds of these surcharges, nor would the surcharges be subject to refund under the CPUC settlement agreement.

DWR Revenues

We act as a pass-through entity for electricity purchased by the DWR on behalf of our customers. Although charges for electricity provided by the DWR are included in the amounts we bill our customers, we deduct from our electric revenues the amounts passed through to the DWR. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers at the CPUC-approved remittance rate. These pass-through amounts are excluded from our electric revenues in our consolidated statements of operations.

Regulatory Assets and Liabilities

We apply Statement of Financial Accounting Standards, or SFAS, No. 71, *Accounting for the Effects of Certain Types of Regulation*, or SFAS No. 71, to our regulated operations. Under SFAS No. 71, regulatory assets represent costs that otherwise would be charged to expense under GAAP. These costs are later recovered through regulated rates. Regulatory liabilities are created by rate actions of a regulator and later will be credited to customers through the ratemaking 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 likely to be recovered under SFAS No. 71, they will be written off at that time. At June 30, 2003, we reported regulatory assets of $2.1 billion, including current regulatory balancing accounts receivable, and regulatory liabilities of $1.2 billion, including current regulatory balancing accounts payable.

Environmental Remediation Liabilities

We record an environmental remediation liability when site assessments indicate remediation is probable and we can estimate a range of reasonably likely cleanup costs. This liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site 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 June 30, 2003, our undiscounted environmental remediation liability was $302 million. Our future environmental remediation liability could increase to as much as $418 million if other potentially responsible parties are not financially able to contribute to these costs, the extent of contamination or necessary remediation is greater than anticipated, or we are found to be responsible for cleanup costs at additional sites.

The process of estimating remediation liabilities is difficult and changes in the estimate could occur given the uncertainty concerning our ultimate liability, the complexity of environmental laws and regulations, the selection of compliance alternatives and the financial resources of other responsible parties.

Our Chapter 11 Filing

Our financial statements are prepared in accordance with the American Institute of Certified Public Accountants Statement of Position, or SOP, 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*, which is used by reorganizing entities operating under the United States Bankruptcy Code, or the Bankruptcy Code. Under SOP 90-7, certain claims against us before our Chapter 11 filing are classified as liabilities subject to compromise. We reported a total of $9.5 billion of liabilities subject to compromise at June 30, 2003. While we operate under the protection of the bankruptcy court, the realization of assets and the liquidation of liabilities are 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.

Results of Operations

The following table sets forth certain operating data for the years ended December 31, 2002, 2001 and 2000 and for the six months ended June 30, 2003 and 2002:

	Six Months Ended June 30,		Year Ended December 31,		
	2003	**2002**	**2002**	**2001**	**2000**
			(in millions)		
Operating revenues					
Electric	$3,299	$3,971	$ 8,178	$ 7,326	$ 6,854
Natural gas	1,498	1,196	2,336	3,136	2,783
Total operating revenues	4,797	5,167	10,514	10,462	9,637
Operating expenses					
Cost of electric energy	1,056	339	1,482	2,774	6,741
Deferred electric procurement cost					(6,465)
Cost of natural gas	806	513	954	1,832	1,425
Operating and maintenance	1,426	1,409	2,817	2,385	2,687
Depreciation, amortization and decommissioning	605	565	1,193	896	3,511
Provision for loss on generation-related regulatory assets and under-collected purchased electricity costs					6,939
Reorganization professional fees and expenses	100	34	155	97	
Total operating expenses	3,993	2,860	6,601	7,984	14,838
Operating income (loss)	804	2,307	3,913	2,478	(5,201)
Reorganization interest income	27	41	71	91	
Interest income	4		3	32	186
Interest expense:					
Contractual interest expense	(377)	(443)	(839)	(810)	(619)
Noncontractual interest expense	(67)	(103)	(149)	(164)	
Other income (expense), net	7	(6)	(2)	(16)	(3)
Income (loss) before income taxes	398	1,796	2,997	1,611	(5,637)
Income tax provision (benefit)	125	731	1,178	596	(2,154)
Income before cumulative effect of a change in accounting principle	273	1,065	1,819	1,015	(3,483)
Cumulative effect of a change in accounting principle (net of income tax benefit of $1 million for the six months ended June 30, 2003)	(1)				

Net income (loss)	272	1,065	1,819	1,015	(3,483)
Preferred dividend requirement	12	12	25	25	25
Income (loss) available for (allocated to) common stock	$ 260	$ 1,053	$ 1,794	$ 990	$ (3,508)

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Overall Results and Income Volatility

Due to the California energy crisis, we have experienced volatility in our results. In 2000, we experienced a significant loss due to the high wholesale energy prices and the write-off of under-collected purchased power and generation-related costs. In 2001, we produced income as one, three and half cent surcharges, made necessary by the California energy crisis, were implemented and wholesale electricity prices moderated during the latter half of the year. Our results for 2002 reflected a full year of the surcharges implemented in 2001 and adjustments associated with the allocated DWR contracts. Results for the first six months of 2003 reflected a decline in operating revenues compared to the same period in 2002. As discussed further below, the results for the first six months of 2002 also included some favorable adjustments to our cost of energy.

Comparison of Six-Month Periods Ended June 30, 2003 and June 30, 2002

Electric Revenues

The following table shows a breakdown of our electric revenues by customer class:

	Six Months Ended June 30,			
	2003	**2002**	**Increase (Decrease)**	**% Change**
		(in millions)		
Residential	$ 1,744	$ 1,759	$ (15)	(0.9)%
Commercial	1,916	1,996	(80)	(4.0)%
Industrial	656	705	(49)	(7.0)%
Agricultural	198	221	(23)	(10.4)%
Subtotal	4,514	4,681	(167)	(3.6)%
Direct access credits	(150)	(190)	40	21.1%
DWR pass-through revenue	(1,351)	(743)	(608)	81.8%
Miscellaneous	286	223	63	28.3%
Total electric operating revenues	$ 3,299	$ 3,971	$ (672)	(16.9)%

Electric operating revenues decreased $672 million, or 17%, for the six months ended June 30, 2003 compared to the same period in 2002 primarily due to the following:

Amounts recorded as pass-through revenue to the DWR increased by $608 million, or 82%, for the six months ended June 30, 2003 compared to the same period in 2002. We pass revenue through to the DWR for electricity provided by the DWR to our customers. The increase in DWR pass-through revenue was primarily due to changes to the methodology used to calculate DWR pass-through revenues beginning in the third quarter of 2002, an additional bond charge passed through to the DWR, which began in November 2002, and an increase in the amount of electricity supplied by the DWR.

From January 2001 through December 2002, the DWR was responsible for procuring electricity required to satisfy the electricity demand of customers not satisfied by electricity from our generation facilities and existing electricity contracts, which we refer to as our net open position. We resumed purchasing electricity on the open market in January 2003, but still relied on electricity provided by the DWR allocated contracts to service a significant portion of our total load. Revenues collected on behalf of the DWR and the DWR s related costs were not included in our consolidated statements of operations, reflecting our role as a billing and collection agent, for which we collected no fees, for the DWR s sales to our customers.

Lower average sales revenue due to a May 2002 CPUC decision that increased baseline quantity allowances. An increase to a customer s baseline quantity allowance increases the amount of the customer s monthly usage that is covered under the lowest possible rate and is exempt from the three cent surcharge.

These effects were partially offset by:

A decrease in direct access credits for the six months ended June 30, 2003 of $40 million, or 21%, compared to the same period in 2002. This decrease was primarily due to a $78 million adjustment that increased direct access credits and industrial customer revenues in the first quarter of 2002. This decrease was partly offset by increases in direct access credits due to increases in revenues recorded in the second quarter of 2003 to include an estimate of $64 million for electricity delivered to customers whose bills have been delayed. In accordance with CPUC regulations, we provide an energy credit to direct access customers who buy their electricity from an alternate energy service provider. We bill direct access customers based on fully bundled rates, which include 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 our estimated procurement and generation cost, and our generation component of the frozen rate for electricity provided by the DWR.

An increase in electricity sales volume due to warmer weather in June 2003 and an increase in the amount recorded in the second quarter of 2003 to include an estimate of $64 million for electricity delivered to customers whose bills were delayed.

Natural Gas Revenues

The following table shows a breakdown of our natural gas revenues:

	Six Months Ended June 30,			
	2003	**2002**	**Increase (Decrease)**	**% Change**
	(revenues, except averages, in millions)			
Bundled gas revenue	$1,485	$1,145	$ 340	29.7%
Transportation service only revenue	133	160	(27)	(16.9)%
Other	(120)	(109)	(11)	10.1%
Total natural gas revenues	$1,498	$1,196	$ 302	25.3%
Average bundled price of natural gas sold per Mcf	$ 8.89	$ 6.54	$2.35	35.9%
Total bundled gas sales (in Bcf)	167	175	(8)	(4.6)%

Bundled natural gas revenue increased $340 million, or 30%, for the six months ended June 30, 2003 compared to the same period in 2002. The increase was primarily a result of a higher average cost of natural gas we purchased from suppliers, which was passed along to customers through higher rates. The average bundled price of natural gas sold increased $2.35 per Mcf, or 36%, for the six months ended June 30, 2003 compared to the same period in 2002.

Transportation service only revenues decreased $27 million, or 17%, for the six months ended June 30, 2003 compared to the same period in 2002. The decrease was primarily due to a decrease in demand for gas transportation services by natural gas-fired electricity generators in California.

Other natural gas revenue primarily includes amounts tracked in natural gas balancing accounts. Over-collections and under-collections are deferred until they are refunded to or received from our customers through rate adjustments.

Cost of Electricity

The following table shows a breakdown of our cost of electricity (which includes the cost of fuel used by our owned generation facilities and electricity purchase costs) and the total amount and average cost of purchased power, excluding in each case the cost and volume of electricity provided by the DWR to our customers:

	Six Months Ended June 30,			
	2003	2002	Increase (Decrease)	% Change
	(costs, except averages, in millions)			
Cost of purchased power	$ 1,145	$ 886	$ 259	29.2%
Proceeds from surplus sales allocated to us	(133)		(133)	(100)%
Fuel used in our generation	44	48	(4)	(8.3)%
Adjustment to purchased power accruals		(595)	595	100%
Total cost of electricity	$ 1,056	$ 339	$ 717	211.5%
Average cost of purchased power per kWh	$ 0.083	$ 0.073	$0.010	13.7%
Total purchased power (in GWh)	13,863	12,138	1,725	14.2%

Our cost of electricity increased $717 million, or 212%, for the six months ended June 30, 2003 compared to the same period in 2002. The increase in the cost of electricity for the six months ended June 30, 2003 was mainly due to a net $595 million reduction to the cost of electricity recorded in March 2002 as a result of FERC and CPUC decisions that allowed us to reverse previously accrued California Independent System Operator, or ISO, charges and to adjust for the amount previously accrued as payable to the DWR for its 2001 revenue requirement. The increase in the cost of electricity also was due to an increase in the total volume of electricity purchased. In the first quarter of 2003, we began buying and selling electricity on the open market in accordance with our CPUC-approved electricity procurement plan. For further information, see the section of this prospectus titled Business Ratemaking Mechanisms Electricity Ratemaking Electricity Procurement Procurement Resumption and the ERRA. Based on the CPUC requirement to perform least-cost dispatch, we are required to dispatch all of the electricity resources within our portfolio, including the DWR allocated contracts, in the most cost-effective way to our ratepayers. This requirement in certain cases requires us to schedule more electricity than is required to meet our retail load and to sell this additional electricity on the open market. This typically occurs when the expected sales proceeds exceed the variable costs to operate a resource or call on a contract.

The increase in total costs was partially offset by proceeds from surplus electricity sales. Proceeds from the sale of surplus electricity are allocated between us and the DWR based on the percentage of volume supplied by each entity to our total load. Our net proceeds from the sale of surplus electricity after deducting the portion allocated to the DWR are recorded as a reduction to the cost of electricity.

Cost of Natural Gas

The following table shows a breakdown of our cost of natural gas:

	Six Months Ended June 30,			
	2003	2002	Increases (Decreases)	% Change
	(costs, except averages, in millions)			
Cost of natural gas sold	$ 738	$ 462	$ 276	59.7%
Cost of gas transportation	68	51	17	33.3%
Total cost of natural gas	$ 806	$ 513	$ 293	57.1%

Average price of natural gas purchased per Mcf	$4.42	$2.64	$1.78	67.4%
Total natural gas purchased (in Bcf)	167	175	(8)	(4.6)%

Our cost of natural gas increased $276 million, or 60%, for the six months ended June 30, 2003 compared to the same period in 2002. The increase was primarily due to an increase in the average market price of natural gas purchased of $1.78 per Mcf, or 67%, for the six months ended June 30, 2003 compared to the same period in 2002.

Our cost to transport natural gas to our service area increased by $17 million, or 33%, for the six months ended June 30, 2003 compared to the same period in 2002. The increase was primarily due to new pipeline transportation charges paid to the El Paso Natural Gas Company, or El Paso. We, along with the other California investor-owned utilities, were ordered by the CPUC in July 2002 to enter into long-term contracts to purchase additional firm transportation services on the El Paso pipeline. Firm transportation service is the dedication of pipeline capacity to the purchaser s natural gas in priority over the natural gas of other capacity purchasers.

Operating and Maintenance

Our operating and maintenance expenses increased $17 million, or 1%, for the six months ended June 30, 2003 compared to the same period in 2002. This increase was primarily due to increases in employee benefit plan-related expenses, public purpose programs spending, customer-related costs and maintenance expenses due to maintenance performed during the scheduled refueling outage at our Diablo Canyon power plant in the first quarter of 2003. These increases were partially offset by lower recorded costs for environmental matters, and a decrease in the recorded liabilities for regulatory matters due to FERC and CPUC decisions on previous transmission owner rate cases and other matters.

Depreciation, Amortization and Decommissioning

Depreciation, amortization and decommissioning expenses increased $40 million, or 7%, for the six months ended June 30, 2003 compared to the same period in 2002. This increase was due mainly to an increase in amortization of the rate reduction bond regulatory asset, which began at the end of January 2002, and an overall increase in our plant assets. Amortization of the rate reduction bond regulatory asset for the six months ended June 30, 2003 increased $20 million from the same period in 2002. The increase reflected the amortization of the regulatory asset for the full six-month period in 2003 compared to the amortization of the regulatory asset for only five months in 2002.

Reorganization Fees and Expenses

In accordance with SOP 90-7, we report reorganization fees and expenses separately on our consolidated statements of operations. These costs primarily include professional fees for services in connection with our Chapter 11 case and totaled $100 million for the six months ended June 30, 2003. This was an increase of $66 million, or 194%, from the same period in 2002. The increase reflected costs associated with preparing for our emergence from bankruptcy.

Interest Income

In accordance with SOP 90-7, we report reorganization interest income separately on our consolidated statements of operations. Interest income primarily includes interest earned on cash accumulated during our Chapter 11 case. Interest income decreased $10 million, or 24%, for the six months ended June 30, 2003 compared to the same period in 2002. The decrease was due primarily to lower average interest rates earned on our short-term investments.

Interest Expense

Our interest expense decreased $102 million, or 19%, for the six months ended June 30, 2003 compared to the same period in 2002. The decrease was due to a reduction of interest on rate reduction bonds and a lower level of unpaid debts accruing interest.

Income Taxes

Income tax expense decreased $606 million, or 83%, for the six months ended June 30, 2003 compared to the same period in 2002. The primary reason for the decline was the 78% decrease in pre-tax income. The effective income tax rate for the six months ended June 30, 2003 was 31% compared to 41% for the same period in 2002. The decrease in the effective income tax rate was primarily due to the effect of regulatory treatment of depreciation differences in the six months ended June 30, 2003 compared to the six months ended June 30, 2002.

Comparison of Years Ended December 31, 2002 and December 31, 2001

Electric Revenues

The following table shows a breakdown of our electric revenues by customer class:

	Year Ended December 31,			
	2002	**2001**	**Increase (Decrease)**	**% Change**
		(in millions)		
Residential	$ 3,646	$ 3,396	$ 250	7.4%
Commercial	4,588	4,105	483	11.8%
Industrial	1,449	1,554	(105)	(6.8)%
Agricultural	520	525	(5)	(1.0)%
Subtotal	10,203	9,580	623	6.5%
Direct access credits	(285)	(461)	176	38.2%
DWR pass-through revenue	(2,056)	(2,173)	117	5.4%
Miscellaneous	316	380	(64)	(16.8)%
Total electric operating revenues	$ 8,178	$ 7,326	$ 852	11.6%

Electric operating revenues for 2002 increased $852 million, or 12%, compared to 2001. This increase in electric operating revenues was primarily due to the following three factors:

The amount of CPUC-authorized surcharges increased $751 million in 2002 from 2001. This increase reflects the collection of $0.035 per kWh in surcharges, effective June 2001, for all of 2002 compared to the collection of these surcharges for only seven months during 2001.

Direct access credits in 2002 decreased $176 million, or 38%, from 2001. The decrease in direct access credits was due to a decrease in the average direct access credit per kWh, which was partially offset by an increase in the total electricity provided to direct access customers by alternate energy service providers. The average direct access credit per kWh was higher in 2001 than in 2002 because in the beginning of 2001 we used the California Power Exchange, or PX, price for wholesale electricity to calculate direct access credits. Since the PX closed 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, alternate energy service providers supplied approximately 7,433 GWh of electricity to direct access customers, compared to 3,982 GWh in 2001.

Revenue passed through to the DWR decreased by $117 million, or 5%, in 2002 from 2001. The decrease in DWR pass-through revenues in 2002 was primarily due to a decrease in our net open position, which was caused by an increase in the number of direct access customers and an increase in the amount of electricity we were able to purchase from qualifying facilities due to renegotiated payment terms through our Chapter 11 case. The decrease in our 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.

Natural Gas Revenues

The following table shows a breakdown of our natural gas revenues:

	Year Ended December 31, 2002	Year Ended December 31, 2001	Increase (Decrease)	% Change
	(revenues, except averages, in millions)			
Bundled gas revenue	$1,882	$3,107	$(1,225)	(39.4)%
Transportation service only revenue	316	375	(59)	(15.7)%
Other	138	(346)	484	139.9%
Total natural gas revenues	$2,336	$3,136	$ (800)	(25.5)%
Average bundled price of natural gas sold per Mcf	$ 6.68	$11.48	$ (4.80)	(41.8)%
Total bundled gas sales (in Bcf)	282	271	11	4.1%

In 2002, our natural gas revenues decreased $800 million, or 26%, 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 decreased $4.80 per Mcf, or 42%, compared to 2001.

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

The increase in other natural gas revenue was 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.

Cost of Electricity

The following table shows a breakdown of our cost of electricity (which includes the cost of fuel used by our owned generation facilities and electricity purchase costs) and the total amount and average cost of purchased power, excluding in each case the cost and volume of electricity provided by the DWR to our customers:

	Year Ended December 31, 2002	Year Ended December 31, 2001	Increase (Decrease)	% Change
	(costs, except averages, in millions)			
Cost of purchased power	$ 1,980	$ 3,224	$(1,244)	(38.6)%
Fuel used in our generation	97	102	(5)	(4.9)%
Other adjustments to cost of electricity	(595)	(552)	(43)	(7.8)%
Total cost of electricity	$ 1,482	$ 2,774	$(1,292)	(46.6)%
Average cost of purchased power per kWh	$ 0.081	$ 0.143	$(0.062)	(43.4)%
Total purchased power (in GWh)	24,552	22,592	1,960	8.7%

The cost of electricity for 2002 decreased $1.3 billion, or 47%, compared to 2001. The decrease was attributable to the following factors:

Our average cost of purchased power decreased in 2002 compared to 2001 primarily as a result of 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 we purchased more electricity from qualifying facilities, other generators and irrigation districts, which provided electricity at a lower cost than the electricity we purchased in the market in the beginning of 2001. In 2002, the DWR purchased all of the electricity needed to meet our customers electricity demands not met by our generation facilities and electricity purchase contracts, whereas in 2001 we purchased the electricity ourselves through the PX market through the first half of January. As previously discussed, we serve as a billing and collection agent for the DWR and therefore do not reflect the DWR s cost of electricity in our 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 that allowed us to reverse previously accrued ISO charges and to adjust the amount of previously accrued pass-through revenues payable to the DWR.

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.

Cost of Natural Gas

The following table shows a breakdown of our cost of natural gas:

	Year Ended December 31,			
	2002	2001	Increase (Decrease)	% Change
	(costs, except averages, in millions)			
Cost of natural gas purchased	$ 853	$1,593	$ (740)	(46.5)%
Cost of gas transportation	101	239	(138)	(57.7)%
Total cost of natural gas	$ 954	$1,832	$ (878)	(47.9)%
Average price of natural gas per Mcf	$3.38	$ 6.77	$(3.39)	(50.1)%
Total price of gas purchased (in Bcf)	252	235	17	7.2%

In 2002, our cost of natural gas decreased $878 million, or 48%, from 2001 primarily due to a decrease of $3.39 per Mcf, or 50%, in the average market price of natural gas purchased.

Additionally, our cost to transport natural gas to our service area decreased significantly in 2002 due to $111 million in costs recognized in 2001 related to the involuntary termination of natural gas transportation hedges caused by a decline in our credit rating. There were no similar events in 2002.

Operating and Maintenance

In 2002, our operating and maintenance expenses increased $432 million, or 18%, from 2001. This increase was mainly due to the following factors:

Increases in employee benefit plan-related expense primarily due to unfavorable returns on plan investments and lower interest rates, which caused a decrease in discount rates on our present-valued benefit obligations;

Increases in environmental liability estimates;

Increases in customer accounts and service expenses related to our new customer billing system;

The amortization of previously deferred electric transmission-related costs, which are collected in rates; and

The deferral of over-collected electric revenue associated with rate reduction bonds. Before 2000, these revenues were used to finance the rate reduction implemented in 1998.

Depreciation, Amortization and Decommissioning

Our depreciation, amortization and decommissioning expenses increased $297 million, or 33%, in 2002 from 2001. This increase was due mainly to amortization of the rate reduction bond regulatory asset that began in January 2002, and totaled $290 million in 2002.

Reorganization Fees and Expenses

In accordance with SOP 90-7, we report reorganization fees and expenses separately on our consolidated statements of operations. Such costs primarily include professional fees for services in connection with our Chapter 11 case and totaled $155 million in 2002 and $97 million in 2001.

Interest Income

In accordance with SOP 90-7, we report reorganization interest income separately on our consolidated statements of operations. Such income primarily includes interest earned on cash accumulated during our Chapter 11 case. Interest income decreased $49 million, or 40%, in 2002 from 2001. The decrease in interest income in 2002 was due in most part to lower average interest rates on our short-term investments.

Interest Expense

In 2002, our interest expense increased $14 million, or 1%, from 2001 due to our Chapter 11 case, which has resulted in higher negotiated interest rates and an increased level of unpaid debts accruing interest.

Income Taxes

Income tax expense increased $582 million, or 98%, in 2002 compared to 2001, primarily due to the 86% increase in pre-tax income. The effective income tax rate for 2002 was 39.3% compared to 37.0% in 2001. The increase was mainly caused by the amortization of deferred tax credits in 2001 associated with generation assets written off. The tax credits were being amortized over the lives of the assets to which they related. When these assets were sold or written off, the tax credits remaining on these assets were amortized into income.

Comparison of Years Ended December 31, 2001 and December 31, 2000

Electric Revenues

The following table shows a breakdown of our electric revenues by customer class:

	Year Ended December 31,			
	2001	**2000**	**Increase (Decrease)**	**% Change**
		(in millions)		
Residential	$ 3,396	$ 3,062	$ 334	10.9%
Commercial	4,105	3,110	995	32.0%
Industrial	1,554	1,053	501	47.6%
Agricultural	525	420	105	25.0%
Subtotal	9,580	7,645	1,935	25.3%
Direct access credits	(461)	(1,055)	594	56.3%
DWR pass-through revenue	(2,173)		(2,173)	
Miscellaneous	380	264	116	43.9%
Total electric operating revenues	$ 7,326	$ 6,854	$ 472	6.9%

Our electric revenues for 2001 increased by $472 million, or 7%, from 2000 and were significantly affected by the following factors:

There was a $594 million decrease in direct access credits in 2001 compared to 2000. This decrease was due to the reduction in total electricity provided to direct access customers by alternate energy service providers and a reduction in the number of direct access customers as the wholesale price of electric power in California increased during 2001.

Electricity surcharges increased revenues in 2001, but were offset by pass-through revenue collected on behalf of the DWR. Electricity surcharges authorized by the CPUC increased revenue in 2001 by

$2.2 billion. The increase provided by electricity surcharges was offset by the pass-through revenue of $2.2 billion for electricity that the DWR provided to our customers. As discussed above, revenues collected on behalf of the DWR and the related costs are not reflected in our consolidated statements of operations.

Conservation efforts by our customers in response to the California energy crisis, mild weather and higher prices from the electricity surcharge implemented in June 2001 reduced electricity sales volumes by 3% in 2001 compared to 2000, lowering electric revenues.

Natural Gas Revenues

The following table shows a breakdown of our natural gas revenues:

	Year Ended December 31,			
	2001	**2000**	**Increase (Decrease)**	**% Change**
	(revenues, except averages, in millions)			
Bundled gas revenue	$3,107	$2,229	$ 878	39.4%
Transportation service only revenue	375	338	37	10.9%
Other	(346)	216	(562)	260%
Total natural gas revenues	$3,136	$2,783	$ 353	12.7%
Average price of natural gas sold per Mcf	$11.48	$ 7.93	$3.55	44.8%
Total bundled gas sales (in Bcf)	271	281	(10)	(3.6)%

In 2001, natural gas revenues increased $353 million, or 13%, 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 increased $3.55 per Mcf, or 45%, compared to 2000. The increase was offset by an approximate 4% 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 natural gas transportation services by natural gas-fired electric generators in California.

The decrease in other gas revenues was 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 Electricity

The following table shows a breakdown of our cost of electricity (which includes the cost of fuel used by our owned generation facilities and electricity purchase costs) and the total amount and average cost of purchased power, excluding in each case the cost and volume of electricity provided by the DWR to our customers:

	Year Ended December 31, 2001	Year Ended December 31, 2000	Increase (Decrease)	% Change
	(costs, except averages, in millions)			
Cost of purchased power	$ 3,224	$ 6,642	$ (3,418)	(51.5)%
Fuel used in our generation	102	99	3	3.0%
Other adjustments to cost of electricity	(552)		(552)	
Deferred electric procurement cost		(6,465)	6,465	100%
Provision for loss on generation-related regulatory assets and under-collected purchased power costs		6,939	(6,939)	(100)%
Total cost of electricity	$ 2,774	$ 7,215	$ (4,441)	(61.6)%
Average cost of purchased power per kWh	$ 0.143	$ 0.152	$ (0.009)	(5.9)%
Total purchased power (in GWh)	22,592	43,762	(21,170)	(48.4)%

The cost of electricity for 2001 decreased $4.4 billion, or 62%, compared to 2000. This decrease was primarily affected by the following factors:

We were no longer purchasing electricity through the PX market. Instead, the DWR purchased 28,640 GWh of electricity on behalf of our customers to cover our customers electricity demands not met by our generation facilities and electricity purchase contracts in 2001.

A statewide energy conservation campaign and mild weather caused our customers to use approximately 3% less electricity in 2001 compared to 2000.

At the end of 2000, we determined that we could no longer conclude that our under-collected wholesale electricity costs and remaining transition costs were probable of recovery in future rates. Accordingly, we charged $6.9 billion to expense at December 31, 2000 as a provision for loss on generation-related regulatory assets and under-collected purchased electricity costs.

Cost of Natural Gas

The following table shows a breakdown of our cost of natural gas:

	Year Ended December 31, 2001	Year Ended December 31, 2000	Increase (Decrease)	% Change
	(costs, except averages, in millions)			
Cost of natural gas purchased	$1,593	$1,331	$ 262	19.7%
Cost of gas transportation	239	94	145	154.3%
Total cost of natural gas	$1,832	$1,425	$ 407	28.6%

Average price of natural gas purchased per Mcf	$ 6.77	$ 5.07	$1.70	33.5%
Total natural gas purchased (in Bcf)	235	262	(27)	(10.3)%

Our cost of natural gas increased $407 million, or 29%, for 2001 compared to 2000 primarily due to an increase in the average cost of natural gas of $1.70 per Mcf, or 34%. Furthermore, as mentioned above, in 2001 our cost to transport natural gas to our service area increased significantly due to $111 million in costs related to the involuntary termination of natural gas transportation hedges.

Operating and Maintenance

In 2001, our operating and maintenance expenses decreased by $302 million, or 11%, from 2000 primarily due to reduced expenses related to the liability for chromium litigation, with respect to which $140 million was recorded in 2000 and nothing in 2001, and lower regulatory and other generation-related costs.

Depreciation, Amortization and Decommissioning

Depreciation, amortization and decommissioning decreased $2.6 billion, or 74%, in 2001 from 2000 due to the accelerated depreciation of generation-related assets in 2000, and as a result of less depreciation being recorded in 2001 as the majority of our generation-related assets were fully depreciated after the acceleration.

Reorganization Fees and Expenses

In accordance with SOP 90-7, beginning with the filing of our Chapter 11 petition in April 2001, we have reported reorganization fees and expenses separately on our consolidated statements of operations. Such costs primarily include professional fees for services in connection with our Chapter 11 case and totaled $97 million for 2001.

Interest Income

In 2001, our interest income decreased $63 million, or 34%, compared to 2000 due primarily to the write-off of generation-related regulatory balancing account interest. The decrease was partially offset by increases in interest on short-term investments and other balancing accounts.

Interest Expense

In 2001, our interest expense increased by $355 million, or 57%, compared to 2000 due to increased debt levels and higher interest rates as a result of our credit rating downgrade.

Income Taxes

Income tax expense was $596 million for 2001. In 2000, we recorded an income tax credit of $2.2 billion. This income tax benefit reflects full utilization of the income tax benefits generated by our pre-tax loss in 2000. We were able to carry back our benefit for federal income taxes and receive a refund of federal income taxes paid in prior years. California provides only for the carryforward of losses. Finally, 2001 includes the amortization of deferred tax credits based on the sale and write off of our generation-related assets to which they related.

Financial Impact of the CPUC Settlement Agreement on Our Results of Operations

As to our past results, in the CPUC settlement agreement, the CPUC agreed that headroom, surcharges and base revenues accrued or collected by us through December 31, 2003 would not be subject to refund. However, if headroom revenues accrued by us during 2003 are greater than $875 million (pre-tax), we must refund the excess to ratepayers and, if headroom revenues are less than $775 million (pre-tax), the CPUC will allow us to collect the shortfall in rates.

The more significant financial impact, however, is on our future operations. As a result of the CPUC settlement agreement, we will record two new regulatory assets. The first regulatory asset is a $2.21 billion after-tax regulatory asset (which is equivalent to an approximately $3.7 billion pre-tax regulatory asset) that the CPUC agreed to establish as a separate and additional part of our rate base. The second regulatory asset, in the amount of approximately $800 million after-tax (which is equivalent to approximately $1.3 billion pre-tax), results from the CPUC s reaffirmation in the CPUC settlement agreement of our adopted 2003 electricity generation rate base as just and reasonable. Recognition of these regulatory assets will result in net income of approximately $3.0 billion and have the effect of increasing our total assets by approximately $5.0 billion.

The recognition of these regulatory assets also will increase our shareholders equity by approximately $3.0 billion. On a pro forma basis after giving effect to the recognition of these regulatory assets, our shareholders equity would have been $7.4 billion at June 30, 2003. This will represent a level comparable to our shareholders equity at December 31, 1997, before California implemented electricity industry restructuring. Recognition of the regulatory assets also will require us to record approximately $2.0 billion of additional deferred tax liabilities. These deferred taxes will be paid as the regulatory assets are amortized and collected in rates.

The implementation of the CPUC settlement agreement also will result in a decrease in our net income in 2004 compared to 2003. The CPUC will reduce our rates by % effective January 1, 2004, causing a decrease in revenues of approximately $. The rates give effect to the amortization of the new regulatory assets. Amortization of the $2.21 billion after-tax regulatory asset in 2004 will be approximately $144 million after-tax, subject to certain reductions, with the amortization each year thereafter increasing, as a result of the nine-year mortgage-style amortization, to $382 million after-tax, subject to certain reductions, in 2012. The generation-related regulatory asset will be amortized on a straight-line basis over the remaining life of our generation assets, an average of approximately 16 years. The amortization of the regulatory assets will have no impact on cash flow as both represent non-cash expenses, similar to depreciation. However, cash flows will be affected by the January 2004 rate change.

Under the CPUC settlement agreement, the unamortized balance of the $2.21 billion after-tax regulatory asset will earn a return on equity of no less than 11.22% annually for its term and, after the equity component of our capital structure reaches 52%, the authorized equity component of this regulatory asset will be no less than 52% for its remaining term regardless of the actual equity component of our capital structure or future authorized return on equity.

Further, under the CPUC settlement agreement, from January 1, 2004 until Moody s Investors Service, Inc., or Moody s, has issued an issuer rating for us of not less than A3 or Standard & Poor s Ratings Services, or Standard & Poor s, has issued a long-term issuer credit rating for us of not less than A-, our authorized return on equity for our CPUC-regulated utility functions will be no less than 11.22% per year and the authorized equity ratio for ratemaking purposes will be no less than 52%, except that for 2004 and 2005, the authorized equity ratio will equal the greater of the proportion of equity in the forecast of our average capital structure for calendar years 2004 and 2005 filed in our cost of capital proceedings and 48.6%.

For a further discussion of the impact of the CPUC settlement agreement on ratemaking see Ratemaking below.

Liquidity and Capital Resources

Overview

At June 30, 2003, we had approximately $4.0 billion of cash and cash equivalents. Of this amount, $234 million is restricted as to its use. We invest our cash in investments of short duration including:

certificates of deposit and time deposits;

bankers acceptances and other short-term securities issued by banks;

asset-backed securities;

repurchase agreements;

commercial paper; and

discounted notes issued or guaranteed by the United States government or its agencies.

The majority of this cash and cash equivalents has been generated since we filed our Chapter 11 petition. Our principal source of cash is payments from our customers. In addition, we have not declared or paid any common or preferred dividends since our credit rating fell below investment grade in January 2001, eliminating one of our significant cash requirements, and the terms of the CPUC settlement agreement prohibit us from

paying dividends on our common stock before July 1, 2004. Since the electricity surcharges were implemented in June 2001 and wholesale electric prices stabilized in mid-2001, the cash generated by our operations has exceeded our cash requirements.

During our Chapter 11 case, we have been meeting all our cash requirements, including the requirements of our capital expenditure program, with internally generated funds. During this period, we have not had access to the capital markets. Other than obligations stayed by the bankruptcy court, we are paying all our obligations as they come due. In addition, we have accrued and paid interest on certain pre-petition liabilities and principal of maturing mortgage bonds with bankruptcy court approval. For more information, see the section of this prospectus titled Description of Our Plan of Reorganization.

The following section discusses the significant changes in our historical cash flows from operating, investing and financing activities.

Operating Activities

Our cash flows from operating activities were as follows:

	Six Months Ended June 30,		Year Ended December 31,		
	2003	2002	2002	2001	2000
			(in millions)		
Net income (loss)	$ 272	$1,065	$ 1,819	$1,015	$(3,483)
Non-cash (income) expenses:					
Depreciation, amortization and decommissioning	605	565	1,193	896	3,511
Net reversal of ISO accrual		(970)	(970)		
Change in accounts payable	252	97	198	1,312	3,063
Change in income taxes payable/receivable	51	493	(50)	1,120	(1,120)
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(62)	(947)	(1,442)	(16)	
Other changes in operating assets and liabilities	86	327	386	438	(1,416)
Net cash provided by operating activities	$1,204	$ 630	$ 1,134	$4,765	$ 555

Net cash provided by operating activities increased by $574 million during the six months ended June 30, 2003 compared to the same period in 2002. This increase was primarily due to the following factors:

Payments on amounts classified as liabilities subject to compromise decreased by $885 million in the six months ended June 30, 2003 compared to the same period in 2002, due to significant pre-petition amounts paid to qualifying facilities in the six months ended June 30, 2002, based on bankruptcy court-approved settlements;

Net income in the six months ended June 30, 2002, included a net $970 million reduction to cost of electricity related to the reversal of accrued ISO charges; and

The increase in net cash provided by operating activities was the result of decreased cash outlays partially offset by a decrease in net income of $793 million.

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:

We filed our Chapter 11 petition in April 2001, which automatically stayed all payments on liabilities incurred before our filing. After the filing, we resumed paying our 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;

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

In 2002, we repaid approximately $901 million in principal owed to qualifying facilities before filing our Chapter 11 petition under bankruptcy court-approved agreements. Among other things, the agreements provided for repayments of amounts owed to qualifying facilities before the filing either in full or in six to 12 monthly installments; and

In 2002, the bankruptcy court issued an order authorizing us to pay pre-petition and post-petition interest to:

- Holders of certain undisputed claims, including commercial paper, senior notes, floating rate notes, medium-term notes, deferrable interest subordinated debentures, prior bond claims, revolving line of credit claims and secured debt claims;

- Trade creditors, including qualifying facilities; and

- Certain other general unsecured creditors.

We paid approximately $1.0 billion in pre-petition 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 $555 million 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.

Investing Activities

Our cash flows from investing activities were as follows:

	Six Months Ended June 30,		Year Ended December 31,		
	2003	2002	2002	2001	2000
			(in millions)		
Capital expenditures	$(730)	$(743)	$(1,546)	$(1,343)	$(1,245)
Net proceeds from sale of assets	11	5	11		6
Other investing activities	13	13	26	5	32
Net cash used by investing activities	$(706)	$(725)	$(1,509)	$(1,338)	$(1,207)

During our Chapter 11 case, capital expenditures have been funded with cash provided by operating activities.

Net cash used by investing activities decreased by $19 million during the six months ended June 30, 2003 compared to the same period in 2002. The decrease was attributable to a decrease in capital expenditures and an increase in net proceeds from the sale of assets during the six months ended June 30, 2003.

Net cash used in investing activities increased by $171 million during 2002, compared to 2001. The increase relates principally to an increase of $203 million in capital expenditures, partially offset by proceeds from asset sales. The capital expenditure increase related primarily to electric transmission substation and line improvements intended to improve system reliability.

Net cash used in investing activities increased by $131 million during 2001 compared to 2000, all of which was attributable to increased capital expenditures. The capital expenditure increase related primarily to electric transmission substation reliability projects.

Financing Activities

Our cash flows from financing activities were as follows:

	Six Months Ended June 30,		Year Ended December 31,		
	2003	2002	2002	2001	2000
			(in millions)		
Common stock repurchased	$	$	$	$	$ (275)
Dividends paid					(475)
Net long-term debt issued, matured, redeemed or repurchased		(333)	(333)	(111)	373
Rate reduction bonds matured	(141)	(141)	(290)	(290)	(290)
Net (repayments) borrowings under credit facilities and short-term borrowings				(28)	2,630
Other financing activities		(1)		(1)	(26)
Net cash provided (used) by financing activities	$ (141)	$ (475)	$ (623)	$ (430)	$ 1,937

Net cash used by financing activities decreased by $334 million during the six months ended June 30, 2003 compared to the same period in 2002. The decrease is mainly due to $333 million in principal repayments on mortgage bonds in the six months ended June 30, 2002, with no such repayment in the six months ended June 30, 2003.

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, we repaid $333 million in principal on our mortgage bonds that matured in March 2002. PG&E Funding LLC, our wholly owned subsidiary, also repaid $290 million in principal on its rate reduction bonds during each of 2001 and 2002. The rate reduction bonds are not included in our Chapter 11 case. PG&E Funding LLC receives funds from which it pays the principal and interest on the rate reduction bonds from a specific rate element in our customer bills. We remit the collection of these billings to PG&E Funding LLC on a daily basis.

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)
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 our April 2001 Chapter 11 filing.

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 principal payments on long-term debt and rate reduction bonds, common stock repurchases and 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

During November 2000, we issued $680 million of senior notes due 2005. The proceeds of these notes were used to finance electricity purchases from the PX. During 2000, $307 million of long-term debt matured or was redeemed.

Cash Requirements of Our Plan of Reorganization

We will use the net proceeds from the initial offering of the debt securities offered by the registration statement of which this prospectus is a part, other financings effected on or about the effective date of our plan of reorganization and cash on hand to pay in full the allowed claims of our creditors (except for the claims of holders of pollution control bond-related obligations that will be reinstated), plus applicable interest on claims in certain classes, and all cumulative dividends in arrears and mandatory sinking fund payments associated with our preferred stock.

We will establish one or more escrow accounts for disputed claims and deposit cash into these accounts. Until paid, the cash portion of disputed claims will earn interest at the same rate as if the cash had been invested in either money market funds consisting primarily of short-term U.S. treasury securities or obligations of or guaranteed by the United States or any agency of the United States, at our option. If the amount of cash deposited into the escrow accounts is insufficient to make the required payments on disputed claims that are later allowed, we will pay the creditor the amount of the cash shortfall. If the amount of cash deposited into the escrow accounts is greater than that needed to make the required payments on disputed claims that are later allowed, we will retain the excess cash.

Timely asserted environmental, fire suppression, pending litigation and tort and workers compensation claims will pass through our Chapter 11 case unimpaired and will be satisfied by us in the ordinary course of business.

Future Liquidity

On or about the effective date of our plan of reorganization, we expect to establish one or more credit facilities in the amount of approximately $ billion. These facilities are intended to be used for the purposes of funding our operating expenses and seasonal fluctuations in working capital, providing letters of credit and, if we deem appropriate, paying allowed claims. We currently anticipate approximately $ of these credit facilities will be available for revolving borrowings and the remaining approximately $ will be allocated to letters of credit. While we expect to enter into these new credit facilities on or about the effective date of our plan of reorganization, there can be no assurance that we will be successful and, if so, on what terms.

We expect that the cash we will retain after the effective date of our plan of reorganization, together with cash generated by our operations and available from the credit facilities which we expect to establish, as described above, will be sufficient to fund our operations and our capital expenditures for the foreseeable future.

Capital Expenditures and Commitments

Capital Expenditures

The safe operation of a utility system requires substantial capital investment. Our investment in plant and equipment totaled approximately $1.5 billion in 2002, $1.3 billion in 2001 and $1.2 billion in 2000. For the first six months of 2003, our capital expenditures totaled $730 million. Over the next five years, our capital expenditures are expected to average approximately $1.7 billion annually.

The following table reflects our estimated capital expenditures over the next five years:

	(in millions)
2004	$ 1,695
2005	$ 1,806
2006	$ 1,569
2007	$ 1,659
2008	$ 1,716

The significant capital expenditure projects include:

New customer connections and expansion of the existing electricity and natural gas distribution systems anticipated to average $400 million annually over the next five years;

Replacements and upgrades to portions of our electricity distribution system anticipated to average approximately $300 million annually over the next five years;

Replacement of natural gas distribution pipelines expected to total approximately $375 million over the next five years;

Substation upgrades and expansion of line capacity of the electric transmission system expected to average approximately $260 million annually over the next five years. Significant individual projects include construction of a 500 kV transmission facility in the Bay Area, a 230 kV transmission facility upgrade in San Francisco, and the upgrade to a section of the transmission system known as Path 15, discussed further below;

Replacements and upgrades to our natural gas transportation facilities expected to total approximately $600 million over the next five years;

Replacement of turbines and steam generators and other equipment at our Diablo Canyon power plant, replacements and upgrades to our hydroelectric generation facilities and costs associated with relicensing our hydroelectric generation facilities expected to average approximately $180 million annually over the next five years; and

Investment in common plant, which includes computers, vehicles, facilities, and communications equipment, expected to average approximately $150 million annually over the next five years.

We anticipate that our capital expenditures in the next five years will be somewhat higher than our capital expenditures in recent years. These additional expenditures are necessary to replace aging and obsolete equipment and to accommodate anticipated electricity and natural gas load growth. We retain some ability to delay or defer substantial amounts of these planned expenditures in light of changing economic conditions and changing technology. It is also possible that these projects may be replaced by other projects. Consistent with past practice, we expect that any capital expenditures will be included in our rate base.

The discussion above does not include any capital expenditures for new generation facilities. While the residual net open position is currently small, it is expected to increase over time. To meet this need, we will need to either enter into contracts with third-party generators for additional supplies of electricity or develop or otherwise acquire additional generation facilities, or satisfy our residual net open position through a combination of the two.

Commitments

Overview. We have substantial financial obligations and commitments related to our financing and operating activities, including the obligations representing allowed claims that we expect to satisfy on, or as soon as practicable after, the effective date of our plan of reorganization.

Financial Commitments. Our current commitments under financing arrangements include obligations to repay mortgage bonds, senior notes, medium-term notes, pollution control bond-related agreements, deferrable interest subordinated debentures, lines of credit, reimbursement agreements associated with letters of credit, floating rate notes and commercial paper. On the effective date of our plan of reorganization, we expect to reinstate certain pollution control bond-related obligations (and in certain events related mortgage bonds), the amount of which will not be determined until shortly before the effective date of our plan of reorganization. The balance of these obligations will be paid in full in cash on or as soon as practicable after the effective date of our plan of reorganization. Following the effective date of our plan of reorganization, our obligations also will include the debt securities issued pursuant to this prospectus in connection with our plan of reorganization and any other financings effected on or about the effective date.

In addition, PG&E Funding LLC must make scheduled payments on its rate reduction bonds. The balance owed on these bonds at December 31, 2002 was $1.45 billion. Annual principal payments on the rate reduction bonds total approximately $290 million. The rate reduction bonds will be fully retired by the end of 2007.

Contractual Commitments. Our contractual commitments include power purchase agreements (including agreements with qualifying facilities, irrigation districts and water agencies, bilateral power purchase contracts, and renewable energy contracts), natural gas supply and transportation agreements, nuclear fuel agreements, and other commitments, including operating leases.

The following table reflects our commitments as of December 31, 2002:

	2003	2004	2005	2006	2007	Thereafter	Total
				(in millions)			
Power purchase agreements:							
Qualifying facilities	$1,680	$1,600	$1,450	$1,350	$1,280	$7,800	$15,160
Irrigation district and water agencies	66	59	52	54	55	692	978
Bilateral contracts	196						196
Renewable energy contracts	42	42	42	42	42		210
Natural gas supply and transportation agreements	595	138	83	26	10		852
Nuclear fuel agreements	59	50	12	13	14	65	213
Other commitments	60	45	39	24	11	11	190(1)
Total(2)	$2,698	$1,934	$1,678	$1,509	$1,412	$8,568	$17,799

(1) Includes commitments for operating lease agreements for office space in the aggregate amount of $55 million, capital infusion agreements for limited partnership interests in the aggregate amount of $26 million, contracts to retrofit generating equipment at our facilities in the aggregate amount of $73 million, load-control and self-generation CPUC initiatives in the aggregate amount of $16 million, and contracts for local and long-distance telecommunications and other software in the aggregate amount of $20 million.

(2) Excludes letters of credit in the amounts of $10 million expiring in 2003 and $620 million expiring in 2004.

Power Purchase Agreements

+ *Qualifying Facilities.* Our power purchase agreements with qualifying facilities require us to pay for energy and capacity. Energy payments are based on the qualifying facility s actual electricity output and capacity payments are based on the qualifying facility s contractual capacity commitment. Capacity payments may be adjusted if the facility fails to meet or exceeds performance requirements specified in the applicable power purchase agreements. 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 dates and will terminate only when the owner of the qualifying facility exercises its termination option. Qualifying facility power purchase agreements accounted for approximately 25% of our 2002 electricity sources and approximately 21% of our 2001 electricity sources. No single qualifying facility accounted for more than 5% of our electricity sources in 2002 or 2001.

their contracts to fix their energy payments at $0.054 per kWh through July 2006. Beginning in August 2006, the energy payments will revert back to the short-run avoided cost rates.

+ *Irrigation Districts and Water Agencies.* We have contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, we must make specified semi-annual minimum payments based on the irrigation districts and water agencies debt service requirements, whether or not any hydroelectric power is supplied (so long as the supplier retains its FERC authorization) and variable payments for operation, maintenance and debt service costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. Our irrigation district and water agency contracts in the aggregate accounted for approximately 4% of our 2002 electricity sources and for approximately 3% of our 2001 electricity sources.

+ *Bilateral Contracts.* At December 31, 2002, we had outstanding two bilateral forward electricity contracts that expire in 2003.

+ *Renewable Energy Requirement.* In June 2003, the CPUC issued a decision pursuant to Senate Bill 1078, or SB 1078, that adopts the framework for a renewable energy portfolio standard requiring each California investor-owned utility to increase purchases of renewable energy by at least 1% of its retail sales per year. By the end of 2017, we must purchase at least 20% of our total electricity from renewable resources. Under SB 1078, we were not obligated to purchase additional renewable energy until we received an investment grade credit rating. However, under subsequently enacted Senate Bill 67, or SB 67, we may be required to purchase additional renewable energy once we are able to do so on reasonable terms and the renewable energy contracts will not impair the restoration of our creditworthiness. Until that time, we will accumulate an annual procurement target, or APT, based on 1% of annual retail sales. When we receive an investment grade credit rating or the CPUC determines that the SB 67 requirements are satisfied, we expect to enter into purchase contracts for renewable energy to meet our accumulated APT.

We currently estimate the annual 1% increase in renewable resource electricity in our portfolio will initially require between 80 and 100 MW of additional renewable capacity to be added per year. The CPUC approved offers we submitted that were sufficient to meet our 2003 renewable energy requirement in December 2002. Pursuant to this approval, we have entered into three contracts with renewable energy suppliers that include both capacity and energy payments. During 2003, electricity under the contracts is sold by the suppliers to the DWR, which resells the electricity to our customers. We expect to reimburse the DWR for the contract costs. After 2003 and once certain conditions are met, we will become obligated under the contracts for the remainder of their five-year terms. We have submitted to the CPUC for approval several contracts intended to meet our 2004 renewable energy requirement. *Natural Gas Supply and Transportation Agreements* We purchase natural gas directly from producers and marketers in both Canada and the United States to serve our core customers. The contract lengths and natural gas sources of our portfolio of natural gas purchase contracts have fluctuated, generally based on market conditions. Currently, we have a $10 million standby letter of credit and a pledge of our natural gas customer accounts receivable for the purpose of securing the purchase of natural gas. The core natural gas inventory also may be pledged, but only if the amount of our natural gas customer accounts receivable is less than the amount that we owe to natural gas suppliers. To date, the amount of our accounts receivable pledge has been sufficient because it has not been less than the amount we owe to natural gas suppliers. The pledged amounts of customer accounts receivable were $220 million at June 30, 2003 and $513 million at December 31, 2002. These arrangements will terminate following the effective date of our plan of reorganization. We also have long-term natural gas transportation service agreements with various Canadian and interstate pipeline companies. These agreements include provisions for payment of fixed demand charges for reserving firm pipeline capacity, as well as volumetric transportation charges. The total

Additional Commitments

Electricity Purchases to Meet Demand. On January 1, 2003, we resumed buying electricity to meet our residual net open position. We had 14 contracts to supply 2003 capacity during peak demand periods, all of which expired after the peak summer months. The contractual commitments table above does not include these contracts, nor does it include contracts we expect to enter into to supply capacity during peak demand periods in the future. In order to enter into these contracts, we have posted, and expect to post, collateral with the ISO and other counterparties. We also buy electricity in short-term market transactions (*i.e.*, forward contracts ranging from one hour ahead to one month ahead).

DWR Allocated Contracts. In January 2003, we became responsible for scheduling and dispatching the electricity subject to the 19 DWR allocated contracts on a least-cost basis. Of these contracts, a total average capacity for 2003 of approximately 2,600 MW is subject to must take contracts, which require the DWR to take and pay for the electricity regardless of need. A total average capacity for 2003 of approximately 1,800 MW is subject to contracts which require the DWR to pay a capacity charge but do not require the purchase of a firm amount of electricity. Energy payments are due only for the power actually delivered. The DWR is currently legally and financially responsible for these contracts and the contractual commitments table above does not include these contracts.

The DWR has stated publicly that it intends to transfer full legal title to, and responsibility for, the DWR allocated contracts to the California investor-owned utilities as soon as possible. However, the DWR allocated contracts cannot be transferred to us without the consent of the CPUC. The CPUC settlement agreement provides that the CPUC will not require us to accept an assignment of, or to assume legal or financial responsibility for, the DWR allocated contracts unless each of the following conditions has been met:

- after assumption, our issuer rating by Moody s will be no less than A2 and our long-term issuer credit rating by Standard & Poor s will be no less than A;
- the CPUC first makes a finding that the DWR allocated contracts being assumed are just and reasonable; and
- the CPUC has acted to ensure that we will receive full and timely recovery in our retail electricity rates of all costs associated with the DWR allocated contracts without further review.

The CPUC settlement agreement does not limit the CPUC s discretion to review the prudence of our administration and dispatch of the DWR allocated contracts consistent with applicable law.

WAPA Sales Contracts Commitments. In 1967, we and the Western Area Power Administration, or WAPA, entered into several long-term power contracts. These contracts give us access to WAPA s excess hydroelectric power and obligate us to provide WAPA with electricity when its resources are not sufficient to meet its requirements. The contracts terminate on December 31, 2004.

The costs to fulfill our obligations to WAPA under the contracts cannot be accurately estimated at this time because both the purchase price and the amount of electricity WAPA will need from us through the balance of

2003 and 2004, when the WAPA contracts terminate, are uncertain. However, we expect that the cost of meeting our contractual obligations to WAPA will be greater than the amount that we receive from WAPA under the contracts. Although it is not indicative of future sales commitments or sales-related costs, our estimated net costs, based upon our portfolio and after subtracting revenues received from WAPA, for electricity delivered under the contracts were approximately $127 million in 2002, approximately $350 million in 2001 and approximately $405 million in 2000. The contractual commitments table above does not include our WAPA commitment.

Advanced Metering Improvements. The contractual commitments table above also does not include any amounts related to the possible implementation of an advanced metering infrastructure to enable the California investor-owned utilities to measure residential and small commercial customers usage of electricity on a time-of-use basis and to apply varying tariffs, or demand responsive tariffs, during peak and non-peak demand periods with the goal of encouraging customers to reduce energy consumption during peak demand periods. Advanced meters are capable of recording usage in time intervals and can be read remotely. While demand responsive tariffs are being implemented for large industrial customers, who already have advanced metering systems in place, a statewide pilot program is in progress to test whether and how much residential and small customers will respond to dynamic, or time varying, rates. If the CPUC determines that it would be cost-effective to install advanced metering on a large scale and orders us to proceed with large scale development of advanced metering for residential and small commercial customers, we expect that we would incur substantial costs to convert our meters, build the meter reading network, and build the data storage and processing facilities to bill a substantial portion of our customers based on dynamic rates.

Path 15 Upgrade. In December 2002, we agreed to participate in a project sponsored by WAPA to upgrade the transfer capability of the section of transmission system known as Path 15, located in central California. The project entails construction of a new 84-mile, 500 kV transmission line by WAPA between two of our existing substations in northern and central California. All the participants have agreed to turn over operational control of the transmission system upgrade to the ISO upon completion of the project. Our share of the costs of this project is approximately $75 million. Our commitments are contingent upon WAPA meeting certain construction milestones. Our commitment for this project is included in the table of estimated capital expenditures.

Contingencies

We have significant gain and loss contingencies that are discussed below.

Nuclear Insurance

We have several types of nuclear insurance for our nuclear power plants. We have insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited, or NEIL. NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to $3.24 billion per incident. Under this insurance, if any nuclear generation facility insured by NEIL suffers a catastrophic loss causing a prolonged accidental outage, we may be required to pay additional annual premiums of up to $36.7 million.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. If one or more acts of domestic terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member within a 12-month period, the maximum recovery under all those nuclear insurance policies may not exceed $3.24 billion plus the additional amounts recovered by NEIL for these losses from reinsurance. Under the Terrorism Risk Insurance Act of 2002, NEIL would be entitled to receive substantial proceeds from reinsurance coverage for an act caused by foreign terrorism. The Terrorism Risk Insurance Act of 2002 expires on December 31, 2005.

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to $10.9 billion. As required by the Price-Anderson Act, we have purchased the maximum available public liability insurance of $300 million for our Diablo Canyon power plant. The balance of the $10.9 billion of liability protection is covered by a loss-sharing program among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of reactors of 100 MW or higher. If a nuclear incident results in costs in excess of $300 million, then we may be responsible for up to $100.6 million per reactor, with payments in each year limited to a maximum of $10 million per incident until we have fully paid our share of the liability. Since our Diablo Canyon power plant has two nuclear reactors of over 100 MW, we may be assessed up to $201.2 million per incident, with payments in each year limited to a maximum of $20 million per incident.

In addition, we have $53.3 million of liability insurance coverage for our retired nuclear generating unit at Humboldt Bay, or Humboldt Bay Unit 3, and have a $500 million indemnification from the NRC for liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of liability insurance.

Workers Compensation Security

We are self-insured for workers compensation. We must deposit collateral with the California Department of Industrial Relations to maintain our status as a self-insurer for workers compensation claims. Acceptable forms of collateral include surety bonds, letters of credit, cash and securities. At June 30, 2003, we provided collateral in the form of approximately $365 million in surety bonds.

In February 2001, several surety companies provided cancellation notices because of our financial situation. The cancellation of these bonds has not impacted our self-insured status under California law. The California Department of Industrial Relations has not agreed to release the canceling sureties from their obligations for claims occurring before the cancellation and has continued to apply the canceled bond amounts, totaling $185 million, towards the $365 million collateral requirement. At June 30, 2003, three additional surety bonds totaling $180 million made up the balance of our collateral. We replaced a $60 million surety bond with a cash deposit of $43 million in October 2003. Corp has guaranteed our reimbursement obligation associated with these surety bonds and our underlying obligation to pay workers compensation claims.

Balancing Account Reserves

In 2002, the CPUC ordered us to create certain electric balancing accounts to track specific electric-related amounts, including revenue shortfalls from baseline allowance increases and costs related to the self-generation incentive program, for which the CPUC has not yet determined specific recovery methods. In the decisions ordering the creation of these balancing accounts, the CPUC indicated that the recovery methods for these amounts would be determined in the future. Because we cannot conclude that the amounts in these balancing accounts are probable of recovery in future rates, we have reserved these balances by recording a charge against earnings. At June 30, 2003, the reserve associated with these balancing accounts was approximately $220 million.

DWR Electricity Revenue Requirement

Because we act as a billing and collection agent for the DWR, amounts collected on behalf of the DWR (related to its revenue requirement) are not included in our revenues.

The DWR filed its proposed 2004 revenue requirement with the CPUC on September 19, 2003. The DWR has proposed a $4.5 billion revenue requirement for power charge-related costs and $873 million in bond charge-related costs in 2004 that would be collected from the customers of the California investor-owned utilities. The CPUC is responsible for allocating the proposed 2004 revenue requirement among the customers of the California investor-owned utilities.

The CPUC s allocation of the DWR revenue requirement for the 2001-2002 period among the three California investor-owned utilities is (and the DWR revenue requirements for 2003 and 2004 may be) subject to adjustments based on the actual amount of electricity purchased by the DWR for the utilities customers during the 2001-2002 period. The CPUC allocated approximately 48.3% of the adopted DWR power charge-related revenue requirement for the 2001-2002 period, or about $4.4 billion, to us.

In testimony we submitted to the CPUC in October 2003, we estimated that we over-remitted $107 million in power charges to the DWR for the 2001-2002 period based on the allocation methodology applied by the CPUC in determining the allocation of the 2001-2002 DWR power charge-related revenue requirement. We also proposed that the CPUC use a different allocation methodology under which we estimate we over-remitted $211 million. Testimony submitted by Southern California Edison and other parties includes varying estimates of our adjustment depending on the allocation method proposed. Southern California Edison calculated that we over-remitted approximately $101 million in power charges to the DWR based on the allocation methodology applied by the CPUC in determining the allocation of the DWR power charge-related revenue requirement. However, Southern California Edison also has proposed that the CPUC apply the allocation methodology used to allocate the DWR bond charge-related revenue requirement to allocate the bond proceeds among the customers of the California investor-owned utilities and, under this methodology, has estimated that we have under-remitted $453 million in DWR revenue requirements. Our testimony noted that the CPUC had already rejected this proposal in its decision allocating the 2003 DWR bond charge-related revenue requirement.

We have proposed to include any adjustments to the 2001-2002 DWR revenue requirement in each California investor-owned utility s allocation of the 2004 DWR revenue requirement to be collected through the DWR remittance rate. Southern California Edison supports this proposal, but San Diego Gas & Electric Company has proposed that any under-remittance be paid by the California investor-owned utility immediately. CPUC hearings are scheduled to begin on October 27, 2003 and the CPUC is expected to issue a decision on the 2001-2002 adjustments (as well as the 2004 DWR revenue requirement) in January 2004.

We expect that any amounts the CPUC determines that we have under-remitted or over-remitted to the DWR for the 2001-2002 period will be included in the DWR revenue requirements in 2004 and subsequent periods, and collected or refunded on a going forward basis from our customers. However, we are unable to predict the outcome of this matter. If the CPUC retroactively determines that we have under-remitted a material amount to the DWR and orders us to make a one-time payment from cash on hand rather than collect the under-remitted amount from customers on a going forward basis, our financial condition and results of operations would be materially adversely affected.

Environmental Matters

We may be required to pay for environmental remediation at sites where we have been, or may be, a potentially responsible party under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended, or CERCLA, and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by us to store, recycle, or dispose of potentially hazardous materials. Under federal and California laws, we may be responsible for remediation of hazardous substances even if we did not deposit those substances on the site.

We record an environmental remediation liability when site assessments indicate remediation is probable and we can estimate a range of reasonably likely cleanup costs. We review our remediation liability on a quarterly basis for each site where we may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure using current technology, enacted laws and regulations, experience gained at similar sites and 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, we record the costs at the lower end of this range.

We had an undiscounted environmental remediation liability of $302 million at June 30, 2003 and $331 million at December 31, 2002. During the six months ended June 30, 2003, the liability was reduced by $29 million primarily due to a reassessment of the estimated cost of remediation. The $302 million accrued at June 30, 2003, includes $105 million related to the pre-closing remediation liability associated with divested generation facilities, and $197 million related to remediation costs for those generation facilities, that we still own, natural gas gathering sites, compressor stations, and manufactured gas plant sites that are either owned by us or are the subject of remediation orders by environmental agencies or claims by the current owners of the former gas plant sites. Of the $302 million environmental remediation liability, we have recovered $155 million through rates charged to our customers, and expect to recover approximately $93 million of the balance in future rates. Any amounts collected in excess of our ultimate obligations may be subject to refunds to ratepayers. We also are recovering our costs from insurance carriers and from other third parties whenever it is possible.

The cost of the hazardous substance remediation is difficult to estimate. The estimate depends on a number of uncertainties, including our responsibility, the complexity of environmental laws and regulations and the selection of compliance alternatives. We estimate the upper limit of the range using assumptions least favorable to us, which is based upon a range of reasonably possible outcomes. Our future undiscounted environmental remediation liability could increase to as much as $418 million if the other potentially responsible parties are not financially able to contribute to these costs, the extent of contamination or necessary remediation is greater than anticipated, or we are found to be responsible for clean-up costs at additional sites.

The California Attorney General filed claims in our Chapter 11 case on behalf of various California state environmental agencies for environmental remediation at numerous sites totaling approximately $770 million. For most of these sites, remediation is ongoing in the ordinary course of business or we are in the process of remediation in cooperation with the relevant agencies and other parties responsible for contributing to the clean-up. Other sites identified in the California Attorney General s claims may not, in fact, require remedial or cleanup actions. Since our plan of reorganization provides that these types of claims will be determined in the applicable administrative or judicial forum and not discharged in our Chapter 11 case, and since we have not argued that our Chapter 11 case relieves us of our obligations to respond to valid environmental remediation orders, we believe the claims seeking specific cash recoveries are unenforceable.

Diablo Canyon Nuclear Power Plant. Our Diablo Canyon power plant employs a once-through cooling water system, which is regulated under a National Pollutant Discharge Elimination System, or NPDES, permit issued by the Central Coast Regional Water Quality Control Board, or the Central Coast Board. This permit allows our Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, our Diablo Canyon power plant s discharge was not protective of beneficial uses.

In October 2000, we reached a tentative settlement of this matter with the Central Coast Board, or the Central Coast settlement agreement, pursuant to which the Central Coast Board agreed to find that the discharge of cooling water from our Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available as defined in the Federal Clean Water Act. As part of the Central Coast settlement agreement, we agreed to take measures to preserve certain acreage north of the plant and will fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On June 17, 2003, the Central Coast settlement agreement was fully executed by us, the Central Coast Board and the California Attorney General s Office. In order for the Central Coast settlement agreement to become effective, among other things, the Central Coast Board must renew our Diablo Canyon power plant s NPDES permit. However, at its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the Central Coast settlement agreement and the Central Coast Board requested its staff to develop additional information on possible mitigation measures.

The California Attorney General has filed a claim in our Chapter 11 case on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with our Diablo Canyon power plant s operation of its cooling water system. We are seeking withdrawal of this claim.

We believe that the ultimate outcome of this matter will not have a material impact on our financial condition or results of operations.

Additional Security Measures. Various federal regulatory agencies have issued guidance and the NRC recently has issued orders regarding additional security measures to be taken at various facilities we own. Our facilities affected by the guidance and the orders include generation facilities, transmission substations and natural gas transportation facilities. The guidance and the orders may require additional capital investment and an increased level of operating costs. However, we do not believe these costs will have a material impact on our consolidated financial condition or results of operations.

Legal Matters

In the normal course of business, we are named as a party in a number of claims and lawsuits. The most significant of these are discussed below. The filing of our Chapter 11 petition automatically stayed the litigation described below, except as otherwise noted.

Chromium Litigation. There are 14 civil suits pending against us in several California state courts relating to alleged chromium contamination. Currently, there are approximately 1,200 plaintiffs in the chromium litigation cases. Approximately 1,260 individuals have filed proofs of claim in our Chapter 11 case, most of whom are plaintiffs in the chromium litigation cases. Approximately 1,035 claimants have filed proofs of claim requesting approximately $580 million in damages and another approximately 225 claimants have filed claims for an unknown amount.

In general, plaintiffs and claimants allege that exposure to chromium at or near our gas compressor stations located at Kettleman and Hinkley, California, and the area of California near Topock, Arizona, caused personal injuries, wrongful death, or other injury and seek related damages. The bankruptcy court has granted certain claimants motion for relief from stay so that the state court lawsuits pending before the Chapter 11 filing can proceed.

We are responding to the suits in which we have been served and are asserting affirmative defenses. We will pursue appropriate legal defenses, including statute of limitations, exclusivity of workers compensation laws, and factual defenses, including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged.

To assist in managing and resolving litigation with this many plaintiffs, the parties agreed to select plaintiffs from three of the cases for a test trial. Ten of these initial trial plaintiffs were selected by plaintiffs counsel, seven plaintiffs were selected by defense counsel, and one plaintiff and two alternates were selected at random. We have filed 13 summary judgment motions challenging the claims of the test trial plaintiffs. Two of these motions are scheduled to be heard in December 2003 and two of these motions are scheduled to be heard in January 2004. We also have filed a motion to dismiss the complaint in one of the cases that is scheduled for hearing on November 14, 2003. The trial of the 18 test cases is scheduled to begin in March 2004.

We have recorded a reserve in our financial statements in the amount of $160 million for these matters. We believe that, after taking into account the reserves recorded at June 30, 2003 with respect to this matter, the ultimate outcome of this matter will not have a material adverse impact on our financial condition or future results of operations.

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

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

The complaints allege that the various defendants, most of whom are pipeline companies or their affiliates, incorrectly measured the volume and heating content of natural gas produced from federal or Indian leases. As a result, the relator alleges that the defendants underpaid, or caused others to underpay, the royalties that were due to the United States for the production of natural gas from those leases.

The complaints do not seek a specific dollar amount or quantify the royalties claim. The complaints seek unspecified treble damages, civil penalties and reasonable expenses associated with the litigation. The relator has filed a claim in our Chapter 11 case for $2.5 billion, $2.0 billion of which is based upon the relator s calculation of penalties sought against us.

We believe the allegations to be without merit and intend to present a vigorous defense. We believe that the ultimate outcome of the litigation will not have a material adverse effect on our financial condition or results of operations.

William Ahern, et al. v. Pacific Gas and Electric Company. On February 27, 2002, a group of 25 ratepayers filed a complaint against us at the CPUC demanding an immediate reduction of approximately $0.035 per kWh in allegedly excessive electricity rates and a refund of alleged over-collections in electricity revenue since June 1, 2001. The complaint claims that electricity rate surcharges adopted in the first quarter of 2001, which increased the average electricity rate by $0.04 per kWh, became excessive later in 2001. The only alleged over-collection amount calculated in the complaint is approximately $400 million during the last quarter of 2001. On April 2, 2002, we filed an answer, arguing that the complaint should be denied and dismissed immediately as an impermissible collateral action and on the basis that the alleged facts, even if assumed to be true, do not establish that currently authorized electricity rates are not reasonable.

On May 10, 2002, we filed a motion to dismiss the complaint. The CPUC has not yet issued a decision. However under the CPUC settlement agreement, the CPUC acknowledges and agrees that the surcharge revenues accrued or collected by us through and including December 31, 2003, are the property of our Chapter 11 estate, have been or will be used for utility purposes, including to pay creditors in our Chapter 11 case, have been included in our retail electricity rates consistent with state and federal law and are not subject to refund.

Our Regulatory Environment

Various aspects of our business are subject to a complex set of energy, environmental and other governmental laws, regulations and regulatory proceedings at the federal, state and local levels.

The FERC, an independent agency within the U.S. Department of Energy, or the DOE, regulates 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, tariffs and conditions of service of the ISO and the terms and rates of wholesale electricity sales. The FERC also has jurisdiction over our electric transmission revenue requirements and rates, the licensing of our hydroelectric generation facilities and the interstate sale and transportation of natural gas.

The CPUC has jurisdiction to set the rates, terms and conditions of service for our electricity distribution, natural gas distribution and natural gas transportation and storage services in California. The CPUC also has jurisdiction over our issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of our electricity and natural gas retail customers, rates of return, rates of depreciation, aspects of the siting and operation of natural gas transportation assets, oversight of nuclear decommissioning utility performance, investigation of many aspects of our business, and certain aspects of our siting and operation of our electric transmission system. Ratemaking for retail sales from our generation facilities is under the jurisdiction of the CPUC.

Ratemaking

2003 General Rate Case Settlements

We have recently entered into two settlement agreements with various intervenors in our 2003 general rate case, both of which have been submitted to the CPUC for approval.

Distribution. In September 2003, we reached an agreement, or the rate case settlement, with various intervenors on all disputed economic issues related to the electricity and natural gas distribution revenue requirements of the 2003 general rate case, with the exception of our request that the CPUC include the costs of a pension contribution in our revenue requirements. The CPUC will resolve the pension contribution issue, as well as other issues raised by non-settling intervenors, in its final decision and our revenue requirement will be adjusted accordingly.

The rate case settlement proposes that we would receive a total 2003 revenue requirement of $2.5 billion for electricity distribution operations, representing a $236 million increase in our total electricity distribution revenue requirement over the currently authorized amount. The rate case settlement provides that the amount of electricity distribution rate base on which we would be entitled to earn an authorized rate of return would be $7.7 billion, based on recorded 2002 plant and including weighted average capital additions for 2003 of $292 million. The rate case settlement also provides for a new balancing account, effective January 1, 2004, to ensure that we recover our authorized total electricity distribution revenue requirement regardless of our level of sales.

The rate case settlement also would result in a total 2003 revenue requirement of $927 million for our natural gas distribution operations, representing a $52 million increase in our total natural gas distribution revenue requirement over the currently authorized amount. The rate case settlement also provides that the amount of natural gas distribution rate base on which we would be entitled to earn an authorized rate of return would be $2.1 billion, based on recorded 2002 plant and including weighted average capital additions for 2003 of $89.2 million.

Generation. In April 2002, the CPUC issued a decision authorizing us to recover reasonable costs incurred in 2002 for our own electricity generation operations, subject to reasonableness review in our 2003 general rate case and other proceedings. In May 2003, the CPUC issued a resolution approving our tariff revisions and our request to establish various balancing and memorandum accounts with modifications in compliance with its April 2002 decision.

In July 2003, we reached an agreement, or the generation settlement, with various intervenors that would set a total 2003 generation revenue requirement of $955 million. This revenue requirements excludes fuel expense, the cost of electricity purchases, the DWR revenue requirement and the nuclear decommissioning revenue requirement. If approved by the CPUC, the generation settlement would resolve all generation-specific issues raised in our 2003 general rate case, but would not resolve various tax methodology issues or the amount of administrative and general expenses and common plant to allocate to generation.

The rate case settlement discussed above would resolve these remaining issues. If the generation settlement and the rate case settlement are approved by the CPUC, our revenue requirement for our electricity generation operations would be set at $912 million for 2003, representing a $38 million increase over the currently authorized amount. In addition, the rate case settlement provides for a new balancing account, effective January 1, 2004, to ensure that we recover our authorized electricity generation revenue requirements regardless of the level of sales.

Under the CPUC settlement agreement, our adopted 2003 electricity generation rate base of $1.6 billion was deemed just and reasonable by the CPUC and not subject to modification, adjustment or reduction, except as necessary to reflect capital expenditures and changes in authorized depreciation. This reaffirmation of our electricity generation rate base allows recognition of an after-tax regulatory asset of approximately $800 million (which is equivalent to approximately $1.3 billion pre-tax).

We cannot predict when or whether the rate case settlement or generation settlement will be approved by the CPUC, or if approved, the outcome of any rehearing petitions or appeals that may be filed.

Attrition Rate Adjustments for 2004-2006

We may receive annual increases in the base revenues established during the test year of a general rate case, known as attrition rate adjustments, for the years between general rate cases to avoid a reduction in earnings in those years due to, among other things, inflation and increases in invested capital. Under the generation settlement and rate case settlement, attrition revenue increases for 2004, 2005 and 2006 would be authorized in the 2003 general rate case. The attrition increase for 2004 and 2005 would be calculated as the prior year s revenue requirement multiplied by the change in the consumer price index. For 2006, the 2005 revenue requirement would be multiplied by the sum of the change in the consumer price index plus 1% to calculate the attrition increase. The generation attrition revenue requirement would also include additional revenues to cover the costs of refueling activities at our Diablo Canyon power plant. For electricity and natural gas distribution operations, the attrition increases would be subject to a minimum increase of 2% and a maximum increase of 3% for 2004, a minimum increase of 2.25% and a maximum increase of 3.25% for 2005, and a minimum increase of

3% and a maximum increase of 4% for 2006. For electricity generation operations, the attrition increases would be subject to a minimum increase of 1.5% and a maximum increase of 3% for 2004 and 2005, and a minimum increase of 2.5% and a maximum increase of 4% for 2006. The rate case settlement notes that outcomes in future cost of capital proceedings could affect our revenue requirements, including the attrition adjustments.

2003 Cost of Capital Proceeding

Our currently authorized return on common equity, or return on equity, is 11.22% and our currently authorized cost of debt is 7.57%. We also have a currently authorized capital structure of 48.00% common equity, 46.20% long-term debt and 5.80% preferred equity. The November 2002 decision in our 2003 cost of capital proceeding adopted these authorized figures, but held the case open to address the effect that implementing and financing a confirmed plan of reorganization would have on our return on equity, costs of debt and preferred equity and ratemaking capital structure. Subsequently, in February 2003, we filed a petition to modify the November 2002 decision to waive the normal requirement that we file a test year 2004 cost of capital application. In May 2003, the CPUC granted our request, exempting us from filing a test year 2004 cost of capital application.

Under the CPUC settlement agreement, the CPUC will set our capital structure and authorized return on equity in our annual cost of capital proceedings in its usual manner; provided that, from January 1, 2004 until Moody s has issued an issuer rating for us of not less than A3 or Standard & Poor s has issued a long-term issuer credit rating for us of not less than A-, our authorized return on equity will be no less than 11.22% per year and our authorized equity ratio for ratemaking purposes will be no less than 52%, except that, for 2004 and 2005, our authorized equity ratio will equal the greater of the proportion of equity in the forecast of our average capital structure for calendar years 2004 and 2005 filed in our cost of capital proceedings and 48.6%.

Procurement Activities

The CPUC has no authority to review the reasonableness of procurement costs in the DWR s contracts, although our administration of the DWR allocated contracts and our least-cost dispatch of the electricity associated with the DWR allocated contracts are subject to a maximum annual procurement disallowance of $36 million. Activities excluded from the disallowance cap include gas procurement activities in support of our new contracts, electricity generation resources, qualifying facilities contracts and certain electricity generation expenses. We can provide no assurance that the CPUC will not increase or eliminate this maximum annual procurement disallowance in the future.

Effective January 1, 2003, we established the energy resource recovery account, or ERRA, to record and recover electricity costs associated with our authorized procurement plan, excluding the costs associated with the DWR allocated contracts. In February 2003, we filed our 2003 ERRA forecast application requesting that the CPUC reset our 2003 ERRA revenue requirement to $1.4 billion. We are authorized to file an application to change retail electricity rates when we reach the trigger threshold (*i.e.*, when our forecasts indicate we will face an under-collection of electricity procurement costs in excess of 5% of our prior year s generation revenues, excluding amounts collected for the DWR). In our February 2003 application, we requested that the CPUC set the trigger threshold at $224 million. The CPUC will finalize our starting ERRA revenue requirement and ERRA trigger threshold after it reviews our ERRA application. We cannot predict when or whether we will reach the trigger threshold. On August 15, 2003, we and the CPUC s Office of Ratepayer Advocates, or the ORA, proposed a stipulation to an administrative law judge and the CPUC that would reduce our 2003 ERRA revenue requirement by $40 million to $1.37 billion. The CPUC issued a decision adopting the stipulation in October 2003.

In August 2003, we filed an application requesting that the CPUC approve the 2004 ERRA forecast revenue requirement of $1.5 billion associated with our 2004 short-term procurement plan and approve as reasonable our ERRA recorded costs for the period from January 2003 through May 2003. We have also asked the CPUC to approve our proposed revenue requirement of $840 million to recover the 2004 costs related to the above-market generation and procurement costs and certain other generation-related costs.

DWR Electricity Revenue Requirement

Although AB IX prohibited the DWR from purchasing electricity on the spot market and from entering into new agreements to purchase electricity after December 31, 2002, the DWR is currently legally and financially responsible for the long-term contracts it entered into before December 31, 2002. The DWR pays for its costs of purchasing electricity from a revenue requirement collected from electricity customers of the three California investor-owned utilities through a charge, called a power charge. Because we act as a billing and collection agent for the DWR, amounts collected on behalf of the DWR (related to its revenue requirement) are not included in our revenues.

In December 2002, the CPUC issued a decision allocating approximately $2.0 billion of the DWR s 2003 $4.5 billion total statewide power charge-related revenue requirement to our customers. This revenue requirement includes the forecasted costs associated with the DWR allocated contracts during 2003.

In July 2003, the DWR submitted a supplemental 2003 revenue requirement to the CPUC that reduced the amount of the total 2003 statewide power charge-related revenue the DWR was requesting by approximately $1.0 billion. On September 4, 2003, the CPUC issued a decision that allocated this $1.0 billion reduction among the customers of the three California investor-owned utilities. The decision allocated approximately $444 million of the reduction to our retail electricity customers and required us to provide a one-time bill credit to our customers to pass through the revenue requirement reduction within 45 days. Prior ambiguities in the formula that determines the calculation of our collections payable to the DWR resulted in our underpayment of amounts to the DWR through June 2003. These ambiguities were resolved by the CPUC in a decision issued on September 4, 2003. At June 30, 2003, we had accrued a $516 million reserve based on our own estimate of underpayments. We subsequently paid the DWR $77 million (which equals the $521 million shortfall ultimately determined to be due to the DWR, less our customers approximately $444 million share of the $1.0 billion statewide reduction in the DWR s 2003 revenue requirement). This approximately $444 million share of the statewide revenue reduction has been returned to our customers in the form of bill credits issued to our customers in September and October 2003. The September 4, 2003 decision also reduces our DWR power charge remittance rate from $0.105 per kWh to $0.095 per kWh effective September 2003. This reduction in the remittance rate is in addition to the approximately $444 million reduction described above.

Our customers also must pay a share of the costs associated with the DWR s $11.3 billion bond offering completed in November 2002. The proceeds of this bond offering were used to repay the State of California and lenders to the DWR for electricity purchases made before the DWR electricity revenue requirement was in place and to provide the DWR with funds needed to make its electricity purchases. The debt service costs are collected from our electricity customers as part of the DWR revenue requirement. We collected and passed through to the DWR from our rates approximately $172 million in bond charges during the six months ended June 30, 2003. We expect to collect and pass through DWR bond charges of approximately $352 million during 2003. In its proposed revenue requirement for 2004, the DWR states that it expects to collect $873 million for bond charges in 2004 that would be collected from the customers of the California investor-owned utilities. The CPUC is responsible for allocating the proposed 2004 bond charge-related revenue requirement among the customers of the California investor-owned utilities. Under the CPUC settlement agreement, the CPUC has agreed that DWR bond charges allocated to our customers will be included in our rates in a manner that will not affect our collection of other authorized costs or return on capital.

The DWR filed its proposed 2004 revenue requirement with the CPUC on September 19, 2003. The DWR has proposed a $4.5 billion revenue requirement for power charge-related costs and $873 million in bond charge-related costs in 2004 that would be collected from the customers of the California investor-owned utilities. The CPUC is responsible for allocating the proposed 2004 revenue requirement among the customers of the California investor-owned utilities.

The CPUC s allocation of the DWR revenue requirement for the 2001-2002 period among the three California investor-owned utilities is (and the DWR revenue requirements for 2003 and 2004 may be) subject to adjustments based on the actual amount of electricity purchased by the DWR for the utilities customers during the 2001-2002 period. The CPUC allocated approximately 48.3% of the adopted DWR power charge-related revenue requirement for the 2001-2002 period, or about $4.4 billion, to us.

In testimony we submitted to the CPUC in October 2003, we estimated that we over-remitted $107 million in power charges to the DWR for the 2001-2002 period based on the allocation methodology applied by the CPUC in determining the allocation of the 2001-2002 DWR power charge-related revenue requirement. We also proposed that the CPUC use a different allocation methodology under which we estimate we over-remitted $211 million. Testimony submitted by Southern California Edison and other parties includes varying estimates of our adjustment depending on the allocation method proposed. Southern California Edison calculated that we over-remitted approximately $101 million in power charges to the DWR based on the allocation methodology applied by the CPUC in determining the allocation of the DWR power charge-related revenue requirement. However, Southern California Edison also has proposed that the CPUC apply the allocation methodology used to allocate the DWR bond charge-related revenue requirement to allocate the bond proceeds among the customers of the California investor-owned utilities and, under this methodology, has estimated that we have under-remitted $453 million in DWR revenue requirements. Our testimony noted that the CPUC had already rejected this proposal in its decision allocating the 2003 DWR bond charge-related revenue requirement.

We have proposed to include any adjustments to the 2001-2002 DWR revenue requirement in each California investor-owned utility s allocation of the 2004 DWR revenue requirement to be collected through the DWR remittance rate. Southern California Edison supports this proposal, but San Diego Gas & Electric Company has proposed that any under-remittance be paid by the California investor-owned utility immediately. CPUC hearings are scheduled to begin on October 27, 2003 and the CPUC is expected to issue a decision on the 2001-2002 adjustments (as well as the 2004 DWR revenue requirement) in January 2004.

We expect that any amounts the CPUC determines that we have under-remitted or over-remitted to the DWR for the 2001-2002 period will be included in the DWR revenue requirements in 2004 and subsequent periods, and collected or refunded on a going forward basis from our customers. However, we are unable to predict the outcome of this matter. If the CPUC retroactively determines that we have under-remitted a material amount to the DWR and orders us to make a one-time payment from cash on hand rather than collect the under-remitted amount from customers on a going forward basis, our financial condition and results of operations would be materially adversely affected.

Qualifying Facilities and Other Existing Bilateral Agreements

Based on a CPUC decision dated April 4, 2002 that established our revenue requirements for our electricity generation operations, the costs of our existing contracts with qualifying facilities and other electricity providers are passed through to ratepayers in full. For 2002, a forecast of approximately $1.8 billion for these costs was adopted. Since the beginning of 2003, we have been recovering the actual costs of qualifying facilities and other power purchase agreements through ratemaking mechanisms, including the ERRA.

Direct Access

In a November 2002 decision, the CPUC established a cost responsibility surcharge, or CRS, mechanism to implement utility-specific non-bypassable charges on direct access customers for their shares of the bond costs and electricity costs incurred by the DWR and the above-market cost related to our own generation resources and electricity purchase contracts. The November 2002 decision imposed a cap on the CRS of $0.027 per kWh. We implemented this capped surcharge on January 1, 2003. A July 2003 decision ordered that the CRS funds be applied to recover (in the following order) the DWR bond charges, our ongoing above-market costs related to our own generation resources and electricity purchase contracts and the DWR power charges. The July 2003 decision found that, subject to prospective adjustment in the annual DWR revenue requirement proceeding, the CRS cap of $0.027 per kWh, plus interest on the direct access CRS under-collection, will be sufficient to repay any shortfall to customers who receive bundled service by the time the DWR allocated contracts terminate. The CPUC has also held in April and July 2003 decisions that certain customers reducing or terminating our electricity service after February 2001 should be responsible for payment of the CRS, subject to specific exemptions.

We do not expect the CPUC s implementation of this decision or the level of the CRS cap to have a material adverse effect on our results of operations or financial condition.

Energy Crisis Refunds

Various parties, including us and the State of California, are seeking up to $8.9 billion in refunds for electricity overcharges during the California energy crisis on behalf of electricity purchasers. On December 12, 2002, a FERC administrative law judge issued an initial decision finding that power suppliers overcharged the California investor-owned utilities, the State of California, and other buyers by $1.8 billion from October 2000 to June 2001 (the only time period for which the FERC permitted refund claims), but that California buyers still owe the power suppliers $3.0 billion, leaving $1.2 billion in net unpaid bills.

In March 2003, the FERC confirmed most of the administrative law judge s findings, but partially modified the refund methodology established by the administrative law judge. In October 2003, the FERC issued a decision confirming the modified refund methodology contained in the March 2003 order. The modified refund methodology included use of a new natural gas price methodology as the basis for mitigated prices and directed the ISO and PX to make compliance filings establishing refund amounts by March 2004. Under the CPUC settlement agreement, we and Corp agreed to continue to cooperate with the CPUC and the State of California in seeking refunds from generators and other energy suppliers. The net after-tax amount of any refunds, claim offsets or other credits from generators or other energy suppliers relating to our PX, ISO, qualifying facilities or energy service provider costs that we actually realize in cash or by offset of creditor claims in the Chapter 11 case, is to be applied by us to reduce the outstanding balance of the regulatory asset created by the CPUC settlement agreement, dollar for dollar. See the section of this prospectus titled Description of Our Plan of Reorganization The CPUC Settlement Agreement Principal Terms Regulatory Asset.

We have recorded $1.8 billion of claims filed by various electricity generators in our Chapter 11 case as liabilities subject to compromise. We currently estimate that these claims would have been reduced to approximately $1.2 billion based on refund methodology recommended in the administrative law judge s initial decision. The recent recalculation of market prices according to the modified methodology adopted by the FERC could result in a reduction of several hundred million dollars in the amount of the suppliers claims. This reduction could be offset by the amount of any additional fuel cost allowance for suppliers if they provide evidence that natural gas prices were higher than the natural gas prices assumed in the refund methodology and accepted by the FERC.

On June 25, 2003, the FERC issued a series of orders directing more than 40 companies to show cause why they should not disgorge profits for a variety of violations of the ISO and PX tariffs related to market manipulation during the summer of 2000. We were one of the companies named in these orders. As to those allegations relating to us, we have submitted information to the FERC showing that some transactions were misidentified and do not relate to us, and that other identified transactions did not constitute improper behavior, but rather were justifiable under then-existing operational circumstances. The FERC staff is expected to determine before November 3, 2003 whether it will continue to investigate us in light of our explanations. Due to the limited dollar amount of our transactions identified as possibly in violation of the tariffs, we do not expect the outcome to have a material adverse impact on our financial condition or results of operations.

The FERC, also in June 2003, began an investigation of why companies should not disgorge profits related to bids for electricity in violation of ISO and PX tariffs during the period from May 1 through October 1, 2000. We submitted information explaining our bidding, which was designed to ensure optimal dispatch of our resources, including when and at what level we operated our hydroelectric generation facilities. We expect that the amount we would be required to pay, if any, would be immaterial and substantially less than the refunds we would receive from other companies. Therefore, we do not expect the outcome to have a material adverse impact on our financial condition or results of operations. This proceeding is being conducted as a FERC staff investigation and results are not expected until the first quarter of 2004.

In addition, the CPUC has opened a proceeding to examine whether the amounts paid to qualifying facilities during the California energy crisis reflect dysfunctional market conditions that warrant a refund of a portion of those payments.

Electric Transmission

On January 13, 2003, we filed an application with the FERC requesting authority to recover $545 million in electric transmission retail rates annually, a 44% increase over the revenue requirement then in effect. The requested increase is mainly attributable to significant capital additions and replacements made to our transmission system to accommodate load growth, maintain the infrastructure and 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%. The January 13 proposed rates went into effect, subject to refund, on August 13, 2003.

On March 28, 2003, we filed an application requesting an update to the rates contained in several of our existing wholesale transmission contracts. The FERC issued an order on May 27, 2003 that will allow the proposed rates for existing transmission contract customers to go into effect, subject to refund, on October 28, 2003. Our proposed rates to these existing transmission contract customers are designed to recover an additional $17 million of revenues on an annual basis.

Under a transmission control agreement, or TCA, entered into as a result of AB 1890, we and the other transmission owners are responsible under the ISO tariff for the costs of the reliability must run agreements between the ISO and owners of the generation facilities subject to reliability must run agreements, or reliability must run plants. Under the reliability must run agreements, reliability must run plants must remain available to generate electricity when needed for local transmission system reliability upon the ISO s demand. At June 30, 2003, the ISO had reliability must run agreements for which we could be obligated to pay an estimated $911 million in net costs during the period from July 1, 2003 to June 30, 2005. The amount will be reduced by amounts we expect to receive under the reliability must run contracts related to our generation facilities. These costs are recoverable under applicable ratemaking mechanisms.

It is possible that we may receive a refund of reliability must run costs that we previously paid to the ISO. In June 2000, a FERC administrative law judge issued an initial decision approving rates that, if affirmed by the FERC, would require the subsidiaries of the Mirant Corporation, or Mirant, that are parties to three reliability must run agreements with the ISO to refund to the ISO, and the ISO to refund to us, excess payments of approximately $300 million, including interest, for availability of Mirant s generation facilities under these agreements. However, on July 14, 2003, the Mirant subsidiaries that are parties to these agreements filed petitions for reorganization under Chapter 11. We are unable to predict at this time when the FERC will issue a final decision on this issue, what the FERC s decision will be and the amount of any refunds, which may be impacted by these Chapter 11 filings, we will ultimately receive. Any cash refunds received would be used to lower future reliability service rates depending on the time period covered by the refunds. If the resolution involves other than a cash refund, it is uncertain how the resolution would be reflected in rates.

We serve as the scheduling coordinator with the ISO for transmission service on the ISO-controlled grid for some of our existing transmission contract customers. The ISO bills us for providing services associated with these customers loads and resources. These ISO charges are referred to as scheduling coordinator costs. In March 2003, we requested that the FERC permit us to recover $83.1 million in scheduling coordinator costs from our existing transmission contract customers for the period from April 1, 1998 to August 31, 2002. Some of our existing transmission contract customers have challenged our request to recover the scheduling coordinator costs from them. Due to these challenges, we are uncertain whether we will be able to fully recover these costs.

Natural Gas Ratemaking

Natural Gas Distribution

The treatment of our natural gas distribution operations in our 2003 general rate case is discussed above under 2003 General Rate Case Settlements Distribution above.

Natural Gas Transportation and Storage

In 1998, we implemented a ratemaking pact called the Gas Accord under which the natural gas transportation and storage services we provide were separated for ratemaking purposes from our distribution services. The Gas Accord established natural gas transportation rates through 2002 and natural gas storage rates through March 2003. Under the Gas Accord, we were at risk of not recovering our natural gas transportation and storage costs and did not have regulatory balancing account protection for over-collections or under-collections of natural gas transportation revenues.

In August 2002, the CPUC approved a settlement agreement, or the Gas Accord settlement, that provided for a one-year extension of our existing natural gas transportation and storage rates and terms and conditions of service, as well as rules governing contract extensions and a contract solicitation period. In January 2003, we filed an amended Gas Accord II application proposing to permanently retain the Gas Accord market structure, extend the incentive mechanism for recovery of core procurement costs, and increase our rates for natural gas transportation service for 2004 and for storage service for the period from April 1, 2004 to March 31, 2005 by $30 million, after removal of the cost of capital issues from this proceeding.

We proposed a 2004 rate increase to be calculated on a demand or throughput forecast basis. In addition, for the 12-month period ending December 31, 2004 for transportation service, and for the 12-month period ending March 31, 2005 for storage service, we propose to provide an option for current holders of contract capacity to extend their rights and for a structured contract solicitation period to be held for any capacity not currently under contract. We may experience a material reduction in natural gas transportation operating revenues if we are unable to renew or replace existing transportation contracts at the beginning or throughout the Gas Accord II period, if we are forced to renew or replace those contracts on less favorable terms than adopted by the CPUC or if overall demand for transportation and storage services is less than anticipated and reflected by the CPUC in rates. A proposed decision in this proceeding is expected in the fourth quarter of 2003. Until the CPUC issues a decision, the natural gas transportation and storage rates set forth in the Gas Accord settlement will continue to be in effect. We cannot predict what the outcome of this proceeding will be, or whether the outcome will materially adversely affect our financial condition or results of operations.

Under the Gas Accord settlement, as with the Gas Accord, we are at risk for any natural gas transportation revenue volatility. Capacity is sold at competitive market-based rates within a cost-of-service tariff framework. Because we sell most of our capacity based on the volumes of natural gas our customers actually ship rather than through long-term firm capacity contracts, our natural gas transportation revenues similarly fluctuate.

Natural Gas Procurement

We set the natural gas procurement rate for our core customers monthly based on the forecasted costs of natural gas, core pipeline capacity and storage costs. We reflect the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas procurement balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rates.

The Gas Accord also established the core procurement incentive mechanism, or CPIM, which is used to determine the reasonableness of our costs of purchasing natural gas for our customers. CPIM purchase costs include reasonable natural gas transportation charges, including demand charges, and natural gas commodity costs. The Gas Accord settlement agreement extended the CPIM for one year through December 2003. Under the CPIM, our purchase costs are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price at indices at the points where we typically purchase natural gas. Costs that fall within a tolerance band, which is currently 99% to 102% around the benchmark, are considered reasonable and are fully recoverable in customers rates. Currently, one-half of the costs outside the tolerance band are recoverable in our customers rates, and our customers receive one-half of the benefit of any savings outside the tolerance band in their rates. However, in June 2003, we reached a settlement with the ORA that, if approved by the CPUC, would increase the amount of savings passed through to ratepayers from one-half to three-fourths, retroactive to November 1, 2002. Under the settlement, ratepayers would continue to bear one-half of the costs incurred above the tolerance band.

Any awards associated with the CPIM normally are reflected annually in the purchased natural gas balancing account after the close of the annual period used to measure the CPIM, which is each 12-month period ending October 31. These awards are not included in earnings until approved by the CPUC.

We filed our annual CPIM report on May 30, 2003, recommending that we receive an award of $2.4 million. The report addresses natural gas procurement costs, interstate and intrastate transportation costs, and ratepayer savings and awards issued to us during the period from November 2001 through October 2002. On September 3, 2003, the ORA issued a report concurring with our recommended award. We anticipate CPUC approval before December 31, 2003.

Capacity Purchases on El Paso and Transwestern Pipelines

In July 2002, the CPUC ordered the California investor-owned utilities to contract for additional amounts of El Paso pipeline capacity to gain firm access to the southwest natural gas producing basins. Since the July 2002 decision, we have signed contracts for capacity on the El Paso pipeline totaling approximately $50.8 million for the period from November 2002 to December 2007. The CPUC pre-approved the costs of these contracts as just and reasonable. The July 2002 decision also ordered the utilities to retain their then-current interstate pipeline capacity levels and sell any excess capacity to third parties only under short-term capacity release arrangements. It also ordered that, to the extent the utilities comply with the decision, they will be able to fully recover their costs associated with existing capacity contracts.

Under a previous CPUC decision, we could not recover in rates any costs paid to Transwestern Pipeline Company, or Transwestern, for natural gas pipeline capacity through 1997. We pay approximately $22 million in annual reservation charges under the Transwestern contract. The Gas Accord provided for partial recovery of Transwestern costs from 1998 forward. See Natural Gas Transportation and Storage above. In June 2003, we reached a settlement with The Utility Reform Network, or TURN, that would allow us to fully recover Transwestern costs beginning in July 2003. The CPUC has not yet approved this settlement.

In December 2002, the CPUC granted our request to recover in rates El Paso pipeline capacity costs and prepayments made to El Paso from all natural gas customers. We began recovering these costs from all natural gas customers in March 2003. We have requested that the CPUC re-allocate all the costs, including Transwestern costs, assuming the CPUC approves our settlement with TURN, to our core customers because the pipeline capacity is used to serve core customers.

El Paso Settlement

In June 2003, we, along with a number of other entities, entered into the El Paso settlement, which resolves all potential and alleged causes of action against El Paso for its part in alleged manipulation of natural gas and electricity commodity and transportation markets during the period from September 1996 to March 2003. Under the El Paso settlement s terms, El Paso will pay approximately $1.5 billion in cash and non-cash consideration. Of that total, approximately $352 million will be paid up front, another approximately $227 million (depending on the proceeds) will be paid from the sale of El Paso stock and approximately $875 million will be paid over 15 to 20 years. El Paso also agreed to a $125 million reduction in El Paso s long-term electricity supply contracts with the DWR and to provide pipeline capacity to California and to ensure specific reserve capacity for us, if needed. The exact amounts allocated to each entity are detailed in a master settlement agreement and delineated in an allocation agreement. The CPUC has issued a draft decision determining the precise means of allocation, under which our natural gas ratepayers would receive approximately $80 million and our electricity ratepayers would receive approximately $216 million. The CPUC expects to complete the final allocation of these refunds during the fourth quarter of 2003. The agreement is now pending approval by the FERC and the San Diego County Superior Court.

It is uncertain when or whether these required approvals will be obtained. The CPUC settlement agreement provides that the net after-tax amount of any consideration that we actually realize in cash related to electricity refunds (but not the natural gas refunds) will reduce the outstanding balance of the new $2.21 billion after-tax regulatory asset if consistent with CPUC rules or orders.

Accounting Pronouncements Issued But Not Yet Adopted

Changes to Accounting for Certain Derivative Contracts

In June 2003, the Financial Accounting Standards Board, or FASB, issued a new Derivatives Implementation Group, or DIG, interpretation of SFAS No. 133, Issue No. C20, *Scope Exceptions: Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature*, or DIG C20. The implementation guidance in DIG C20 is effective prospectively for all existing and all future derivative contracts in the fourth quarter of 2003. We currently are evaluating the impacts, if any, of DIG C20 on our consolidated financial statements.

Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity*, or SFAS No. 150. The requirements of SFAS No. 150 are applicable to us in the third quarter of 2003. SFAS 150 will be implemented by reclassifying and remeasuring our preferred stock with mandatory redemption provisions. The remeasurement and reclassification will not have a significant impact on our earnings. Our preferred stock with mandatory redemption provisions will be reflected on the balance sheet as a liability using present value techniques. Any differences between the current carrying value and the remeasured amount will be accounted for as a cumulative effect of a change in accounting principle. Beginning July 2003, we will record dividends on our preferred stock with mandatory redemption provisions and any payments in excess of its carrying amount as interest expense. We will not reclassify dividends paid or accrued in prior periods.

Determining Whether an Arrangement Contains a Lease

In May 2003, the Emerging Issues Task Force, or EITF, reached consensus on EITF 01-8, *Determining whether an Arrangement Contains a Lease*, or EITF 01-8. EITF 01-8 establishes criteria to be applied to any new or modified agreement in order to ascertain if such agreement is in effect a lease, and subject to lease accounting treatment and disclosure requirements principally found in SFAS No. 13, *Accounting for Leases.* EITF 01-8 is effective for all new or modified arrangements entered into as of July 1, 2003. We currently are assessing the impact of EITF 01-8.

Amendment of Statement 133 on Derivative Instruments and Hedging Activities

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, or SFAS No. 149. SFAS No. 149 amends and clarifies the accounting and reporting for derivative instruments, including certain derivatives embedded in other contracts, and for hedging activities under SFAS No. 133. SFAS No. 149 clarifies under what circumstances a contract with an initial net investment meets the characteristics of a derivative according to SFAS No. 133 and when a derivative contains a financing component that warrants special reporting in the statement of cash flows.

The requirements of SFAS No. 149 are effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. We currently are evaluating the impacts, if any, of SFAS No. 149 on our consolidated financial statements.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation No. 46, *Consolidation of Variable Interest Entities*, or 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 or arrangement with which it is involved. A variable interest entity is an entity that does not have sufficient equity investment at risk to permit the entity to finance its activities without additional subordinated financial support from other parties or an entity where equity investors lack the essential characteristics of a controlling financial interest.

Until the issuance of FIN 46, a 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. There were no new variable interest entities created by us between February 1, 2003 and June 30, 2003. The consolidation requirements are applicable to us in the fourth quarter of 2003. We are evaluating the impacts of FIN 46 s initial recognition, measurement and disclosure provisions on our consolidated financial statements, and currently are unable to estimate variable interest entities that will be consolidated or disclosed when FIN 46 becomes effective.

We have investments in unconsolidated affiliates, which are mainly engaged in the purchase of residential real estate. It is possible that we will be required to consolidate our interests in two of these entities as a result of the adoption of FIN 46. As of June 30, 2003, our recorded investment in these entities is approximately $16 million. As a limited partner, our exposure to potential loss is limited to our investment in each partnership.

Customer Information System

We implemented a new customer information system at the end of 2002 and continue to work through various billing and collection issues associated with the change over to the new system. The implementation has, among other things, required us to put into place new processes for recording and estimating revenues and electricity-related costs. We do not expect the system changes to have a significant impact on our financial condition and results of operations.

Employee Benefit Plans

On May 28, 2003, we remeasured the assets and liabilities of our defined benefit pension plan. In connection with the remeasurement, which reflected a reduction in the current discount rate from the defined benefit pension plan s previous actuarial valuation, we recorded a minimum pension obligation of $478 million, the amount by which the accumulated benefit obligation exceeded the fair market value of plan assets, and reduced our pension asset from $887 million to $353 million. We previously recognized a regulatory liability for timing differences between recognition of pension costs in accordance with GAAP and ratemaking purposes. As a result of the remeasurement, we reduced this regulatory liability by $911 million. The remaining amount of $60 million, net of income tax benefit of $41 million, has been recorded as a component of shareholders equity in our consolidated balance sheets. The charge to other comprehensive income does not affect earnings or cash flow, and could be reversed in future periods if the fair value of plan assets exceeds the accumulated benefit obligation. Our defined benefit pension plan currently exceeds the minimum funding requirements of the Employee Retirement Income Security Act of 1974.

Related Party Transactions

In accordance with various agreements, we and other subsidiaries of Corp provide to Corp and receive from Corp various services. We and Corp exchange administrative and professional support services in support of operations. These services are priced either at the fully loaded cost (*i.e.*, direct costs and allocation of overhead costs) or at the higher of fully loaded cost or fair market value, depending on the nature of the services. Corp also allocates certain other corporate administrative and general costs to us and other subsidiaries using a variety of factors, including the number of employees, operating expenses excluding fuel purchases, total assets, and other cost-causal methods. We purchase natural gas transportation services from Gas Transmission Northwest Corporation, or GTN. Effective April 1, 2003, we no longer purchase natural gas from National Energy and Gas Transmission Energy Trading Holdings Corporation, or NEG ET. Both GTN and NEG ET are subsidiaries of National Energy and Gas Transmission, Inc., or NEGT, a subsidiary of Corp. Our significant related party transactions and related receivable (payable) balances were as follows:

	Six Months Ended June 30,		Year Ended December 31,			Receivable (Payable) Balance Outstanding at	
	2003	2002	2002	2001	2000	June 30, 2003	December 31, 2002
				(in millions)			
Revenues from:							
Administrative services provided to Corp	$ 4	$ 3	$ 7	$ 6	$ 12	$ 2	$ 1
Gas reservation services provided to NEG ET	4	6	9	11	12		
Contribution in aid of construction received from NEGT			2	5	3		3
Trade deposit due from GTN	3			11		15	12
Expenses from:							
Administrative services received from Corp	$ 98	$ 50	$ 106	$ 127	$ 83	$ (358)	$ (289)
Interest accrued on pre-petition liability due to Corp	4		8	3	3	(2)	(2)
Administrative services received from NEGT	2		2			(1)	(2)
Software purchases from NEG ET	1						
Gas commodity services received from NEG ET	10	28	49	120	136	(1)	(26)
Gas transportation services received from GTN	29	22	47	40	46	(8)	(8)
Trade deposit due to NEG ET	1		7			(5)	(7)

Payment of outstanding amounts owed to us as of July 8, 2003, the date of NEGT s Chapter 11 filing, are subject to the approval of the U.S. Bankruptcy Court for the District of Maryland.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Risk Management Activities

We are exposed to various risks associated with our operations, the marketplace, contractual obligations, financing arrangements and other aspects of our business. Our risk management programs are designed to support business objectives, minimize costs, discourage unauthorized risk, reduce the volatility of earnings and manage cash flows. 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.

We use derivatives for risk mitigation purposes. We may use energy and financial derivatives and other instruments and agreements to mitigate the risks associated with an asset, a liability, a committed transaction or a probable forecasted transaction.

Price Risk

Price risk is the risk that changes in commodity market prices will adversely affect earnings and cash flows.

We have entered into long-term contracts for capacity and energy purchases from qualifying facilities, natural gas transportation and nuclear fuel for our Diablo Canyon power plant. Substantially all of these contracts meet the criteria of normal purchases and sales as defined in, and are exempt from the requirements of, SFAS No. 133, including mark-to-market valuation. Many of these contracts contain fixed prices. For more information regarding the amounts we must pay under these contracts, see the section of this prospectus titled Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital Expenditures and Commitments Commitments.

We purchase natural gas in western Canada and the southwestern United States, principally on the spot market. We have entered into contracts with natural gas traders intended to hedge our natural gas commodity price risk. We also use derivative instruments to hedge our exposure to changes in foreign currency exchange rates. These contracts qualify as cash-flow hedges under SFAS No. 133 and are presented at fair value on our consolidated balance sheet.

We have described below the value-at-risk methodology, which is our method for assessing the prospective risk that exists within a portfolio for price risk.

Electric Commodity Price Risk

On January 1, 2003, we became responsible for scheduling and dispatching on a least-cost basis electricity allocated under 19 of the contracts entered into by the DWR to fulfill our customers electricity requirements. While the DWR continues to be legally and financially responsible for these contracts, we rely on electricity provided by the DWR allocated contracts to service a significant portion of our total load. We bill our customers for these DWR electricity purchases and remit amounts collected to the DWR based on the DWR s CPUC-approved revenue requirement.

Beginning January 1, 2003, we began purchasing electricity on the spot market to meet our residual net open position. Our residual net open position will increase over time for a number of reasons, including:

- periodic expirations of our existing electricity purchase contracts;
- periodic expirations or other terminations of the DWR allocated contracts; and
- increases in our customers electricity demands due to customer and economic growth or other factors.

In addition, unexpected outages at our Diablo Canyon power plant or any of our other significant generation facilities, or a failure to perform by any of the counterparties to our electricity purchase contracts or the DWR allocated contracts, would immediately increase our residual net open position.

In December 2002, the CPUC issued an interim opinion granting us authority to enter into contracts designed to meet and to hedge our residual net open position through the first quarter of 2004. We had 14 contracts to supply 2003 capacity during peak demand periods, all of which expired after the peak summer months. We expect to enter into contracts to supply capacity during peak demand periods in the future. In order to enter into these contracts, we have posted and expect to post, collateral with the ISO and other counterparties. We also buy electricity in short-term market transactions (*i.e.*, forward contracts ranging from one hour ahead to one month ahead).

California s Senate Bill 1976, or SB 1976, directed the CPUC to increase our rates if the available revenues do not cover our forecasted costs of purchasing electricity, and this shortfall exceeds 5% of our prior year s generation revenues, excluding amounts collected for the DWR.

The amount of electricity provided by the DWR allocated contracts will likely result in surplus electricity during certain periods. We plan to sell this surplus electricity on the open market. Proceeds from the sale of surplus electricity are allocated between us and the DWR based on the percentage of volume supplied by each entity to our total load. Our share of surplus sales revenues are included in our calculation determining whether we face an under-collection of electricity procurement costs and are subject to review and recovery within the ERRA procedures discussed under Ratemaking Procurement Activities.

Nuclear Fuel

We have purchase agreements for nuclear fuel. We rely on large, well-established international producers for our long-term nuclear fuel agreements in order to diversify our commitments and ensure security of supply. Pricing terms are also diversified, ranging from fixed prices to base prices that are adjusted using published information.

Nuclear fuel purchases are subject to tariffs of up to 50% on imports from certain countries. Our nuclear fuel costs have not been increased by these tariffs because the terms of the existing long-term contracts do not include such costs. However, once these contracts expire in 2004, the costs under new nuclear fuel contracts may increase. As noted above, the CPUC is obligated to change retail electricity rates at any time that we will face an under-collection of electricity costs, including the cost of nuclear fuel, in excess of 5% of our prior year s generation revenues, excluding amounts collected for the DWR.

Natural Gas Commodity Price Risk and Transportation Revenue Risk

We recover our natural gas purchase costs through billings to our customers. Under the CPIM, we are allowed to adjust the natural gas rates in our bills on a monthly basis. Our purchase costs are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where we typically purchase natural gas. Costs that fall within a tolerance band, which is 99% to 102% around the benchmark, are considered reasonable and are fully recovered in customer rates. Currently, one-half of the costs outside the tolerance band are recoverable in our customers rates, and our customers receive the benefits of one-half of any savings outside the tolerance band in their rates. However, in June 2003, we reached a settlement with the ORA that, if approved by the CPUC, would increase the amount of savings passed through to ratepayers from one-half to three-fourths, retroactive to November 1, 2002. Under the settlement, ratepayers would continue to bear one-half of the costs incurred above the tolerance band.

In addition, we have contracts for natural gas transportation capacity on various natural gas pipelines. In July 2002, the CPUC ordered California investor-owned utilities to contract for a certain amount of El Paso pipeline capacity to gain firm access to the southwest natural gas producing basins. The CPUC pre-approved the costs of these contracts as just and reasonable. The July 2002 decision also ordered the utilities to retain their then-current interstate pipeline capacity levels and sell any excess capacity to a third party under short-term capacity release arrangements. It also ordered that, to the extent the utilities comply with the decision, they will be able to fully recover their costs associated with existing capacity contracts.

Under a previous CPUC decision, we could not recover any costs paid to Transwestern for gas pipeline capacity through 1997. The Gas Accord provided for partial recovery of Transwestern costs from 1998 forward.

In June 2003, we reached a settlement with TURN that would allow us to fully recover Transwestern costs beginning in July 2003. The CPUC has not yet approved the settlement.

Under the Gas Accord settlement, as with the Gas Accord, we are at risk for any natural gas transportation revenue volatility. Capacity is sold at competitive market-based rates within a cost-of-service tariff framework. We currently face price risk for the part of our intrastate natural gas transportation capacity that is not used by our core customers. There are significant seasonal and annual fluctuations in demand for natural gas transportation services. Because we sell most of our capacity based on the volume of natural gas our customers actually ship rather than through long-term firm capacity contracts, our natural gas transportation revenues similarly fluctuate.

Value-at-Risk

We 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 relies on 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 movement data and specific, defined mathematical parameters to estimate the characteristics of and the relationships between components of assets and liabilities held for risk management activities.

Our value-at-risk calculation is a dollar amount reflecting the maximum potential one-day loss in the fair value of our portfolios due to adverse market movements over a defined time horizon within a specified confidence level. This calculation is based on a 95% confidence level, which means that there is a 5% probability that our portfolio 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% 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 also would be a 5% probability that a one-day price movement would be greater than $5 million.

Our value-at-risk exposure is limited to derivatives in our natural gas portfolio, excluding financial options. 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 comparison of daily values-at-risk at June 30, 2003, and at December 31, 2002, is included below in order to provide context around the one-day amounts. The average, high and low valuations represent the average, highest and lowest values during the year ended December 31, 2002 and the six months ended June 30, 2003.

		Average	High	Low
		(in millions)		
June 30, 2003(1)	$ 5	$4.5	$6.6	$1.7
December 31, 2002(1)	$ 4	$2.1	$5.8	$0.3

(1) Includes our natural gas portfolio only.

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 regulatory and legislative risks that we face.

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 us include the risk of increasing interest rates on variable rate obligations. At June 30, 2003, our interest rate exposure on debt that may be reinstated under our plan of organization was limited to obligations associated with $614 million aggregate principal amount of pollution control bonds that mature in 2003 and 2004.

Credit Risk

We had accounts receivable of $1.8 billion at June 30, 2003, $1.9 billion at December 31, 2002 and $2.1 billion at December 31, 2001. The majority of the accounts receivable are associated with residential and small commercial customers. Based upon historical experience and evaluation of then-current factors, we recorded an allowance for doubtful accounts of $62 million, $59 million and $48 million, respectively, against those accounts receivable at those dates. Further, in accordance with our tariffs, we limit our exposure to credit risk by requiring deposits from new customers and from those customers whose past payment practices are below standard.

We also conduct business with customers or vendors primarily in the energy industry, including other California 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 our overall exposure to credit risk because larger commercial counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions. We manage credit risk by assigning credit limits to counterparties based on an evaluation of a counterparty s financial condition, net worth, credit rating, and other credit criteria as deemed appropriate. We monitor each counterparty s credit limit and credit quality frequently and prepare a detailed credit analysis for each counterparty at least annually.

Credit exposure is calculated daily and, if that exposure exceeds our established limits, we take immediate action to reduce the exposure, or obtain additional collateral, or both. Further, we rely heavily on master agreements that require our larger commercial counterparties to post security in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits. Gross credit exposure for these counterparties, defined as the current mark-to-market value of the contract plus or minus any outstanding net receivables or payables, was $220 million at June 30, 2003, $288 million at December 31, 2002, and $271 million at December 31, 2001. We have received collateral from our larger commercial counterparties (in the form of cash deposits and letters of credit) totaling $55 million at June 30, 2003, $113 million at December 31, 2002, and $127 million at December 31, 2001. At June 30, 2003, we had one counterparty to which our net exposure totaled approximately $28 million. This counterparty is rated investment grade. In addition, we had net credit exposure of approximately $18 million at June 30, 2003, to a counterparty that is not investment grade. No other counterparty made up over 10% of our net credit exposure as of that date.

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. We are exposed to risks associated with foreign currency exchange variations related to Canadian-denominated purchase and swap agreements.

Changes in natural gas purchase costs due to fluctuations in the value of the Canadian dollar are passed through to customers in rates, as long as the overall costs of purchasing natural gas are within a tolerance band included in the CPIM mechanism discussed above.

Based on obligations in Canadian dollars at June 30, 2003, a 10% appreciation of the Canadian dollar would not be material to us.

DESCRIPTION OF OUR PLAN OF REORGANIZATION

Background

In 1998, the State of California implemented electricity industry restructuring and established a framework allowing generators and other power 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 recovering our generation-related costs that were expected to be uneconomic under the new market framework. State regulatory action further required us to divest a majority of our fossil fuel-fired generation facilities and made it economically unattractive to retain our remaining generation facilities. The resulting sales of generation facilities in turn made us more dependent on the newly deregulated wholesale electricity market.

Beginning in May 2000, wholesale prices for electricity began to increase. Since our retail electricity rates remained frozen, we financed the higher costs of wholesale electricity by issuing debt and drawing on our credit facilities. Our inability to recover our electricity purchase costs from customers ultimately resulted in billions of dollars in defaulted debt and unpaid bills and caused us to file a voluntary petition for relief under Chapter 11 on April 6, 2001. Pursuant to Chapter 11, we have retained control of our assets and are authorized to operate our business as a debtor-in-possession while subject to the jurisdiction of the bankruptcy court.

We and Corp filed a plan of reorganization for us in September 2001. This original plan of reorganization proposed to disaggregate our historic businesses into four separate entities, only one of which would have been primarily subject to the regulation of the CPUC. In April 2002, the CPUC, later joined by the Official Committee of Unsecured Creditors, or OCC, filed an alternative plan. The CPUC plan of reorganization would not have separated our businesses and we would have remained primarily subject to CPUC regulation. The hearing on the confirmation of the CPUC plan of reorganization began in November 2002 and the hearing on the confirmation of our original plan of reorganization began in December 2002. Subsequently, the bankruptcy court stayed all plan confirmation proceedings and required us, the CPUC and certain other parties to participate in a judicially supervised settlement conference to explore the possibility of resolving the differences between the competing plans of reorganization and developing a consensual plan.

The CPUC Settlement Agreement

On June 19, 2003, we, Corp and the staff of the CPUC announced the terms of the CPUC settlement agreement. It was approved by the CPUC on , 2003 and executed by all parties on , 2003.

In the CPUC settlement agreement, we and Corp agreed that we would remain a vertically integrated utility primarily under CPUC regulation. The CPUC settlement agreement allows for resolution of our Chapter 11 proceeding on terms that will permit us to emerge from Chapter 11 as an investment grade rated company with investment grade rated debt (at least Baa3 by Moody s and at least BBB- by Standard & Poor s), and pay in full all our valid creditor claims, plus applicable interest.

The CPUC settlement agreement contains a statement of intent that it is in the public interest to restore us to financial health and maintain and improve our financial condition in the future to ensure that we are able to provide safe and reliable electricity and natural gas service to our customers at just and reasonable rates. In addition, the CPUC settlement agreement includes a statement of intent that it is fair and in the public interest to allow us to recover prior uncollected costs over a reasonable time and to provide the opportunity for our shareholders to earn a reasonable rate of return on our business. Under the CPUC settlement agreement, we will release claims against the CPUC that we or Corp would have retained under the original plan of reorganization.

Principal Terms

Regulatory Asset

The CPUC agreed to establish a $2.21 billion after-tax regulatory asset (which is equivalent to an approximately $3.7 billion pre-tax regulatory asset) as a new, separate and additional part of our rate base that will be amortized on a mortgage-style basis over nine years beginning January 1, 2004. Under this amortization, annual collections in electricity rates of this regulatory asset will range from $144 million after-tax in 2004 to $382 million after-tax in 2012, in both cases subject to certain reductions. The regulatory asset will be fully amortized by the end of 2012. The CPUC also has agreed to authorize us to establish a tax tracking account, to be used if we must pay income tax on the regulatory asset before it is fully amortized, to record the difference between taxes on the regulatory asset plus interest imposed by federal or state tax authorities for earlier recognition and taxes that would have been incurred on account of the regulatory asset had it been taxed during the amortization period. The tax tracking account would earn the authorized rate of return and be amortized into rates over the longer of the remaining life of the regulatory asset or five years.

The net after-tax amount of any refunds, claim offsets or other credits from generators or other energy suppliers relating to our PX, ISO, qualifying facilities or energy service provider costs during the California energy crisis that we actually realize in cash or by offset of creditor claims in our Chapter 11 case shall be applied by us to reduce the outstanding balance of the regulatory asset, dollar for dollar. Similarly, the net after-tax amount of any consideration we actually realize in cash related to electricity refunds (not natural gas refunds) under the master settlement agreement that resolves the litigation in *Public Utilities Commission of the State of California v. El Paso Natural Gas Co., et al.*, FERC Docket No. RP00-241-00, and related state and federal court litigation, if consistent with CPUC rules or orders concerning the consideration paid by El Paso under the master settlement agreement, also will cause a reduction in the outstanding balance of the $2.21 billion after-tax regulatory asset. See the section of this prospectus titled Business Ratemaking Mechanisms Natural Gas Ratemaking Interstate and Canadian Natural Gas Transportation and Storage El Paso Settlement.

The unamortized balance of the $2.21 billion after-tax regulatory asset will earn a return on equity of no less than 11.22% annually for its term and, after the equity component of our capital structure reaches 52%, the authorized equity component of this regulatory asset will be no less than 52% for the remaining term.

Ratemaking Matters

Our adopted 2003 electricity generation rate base of $1.6 billion was deemed just and reasonable by the CPUC and not subject to modification, adjustment or reduction, except as necessary to reflect capital expenditures and changes in authorized depreciation. This reaffirmation of our electricity generation rate base allows recognition of an after-tax regulatory asset of approximately $800 million (which is equivalent to approximately $1.3 billion pre-tax).

The CPUC will timely act upon our applications to collect in rates prudently incurred costs of (including return of and return on) any new, reasonable investment in utility plant and assets. The CPUC will promptly adjust our rates consistent with SB 1976 and the CPUC s 2002 agreement with the DWR regarding establishment of the DWR s revenue requirements to ensure that we collect in our rates our fixed amounts to service existing rate reduction bonds, regulatory asset amortization and return, and our base revenue requirements (*e.g.*, electricity and natural gas distribution, our rate base for our electricity generation, gas commodity procurement, existing qualifying facility contract costs and associated return). The CPUC settlement agreement provides that the CPUC will not discriminate against us because of our Chapter 11 case, our federal lawsuit against the CPUC commissioners to recover our previously incurred costs of providing electricity service from ratepayers under the federal filed rate doctrine, the CPUC settlement agreement, the regulatory asset or any other matters addressed in or resolved by the CPUC settlement agreement.

Our retail electricity rates are maintained at current levels through December 31, 2003. As of January 1, 2004, the CPUC may adjust our retail electricity rates prospectively consistent with the CPUC settlement agreement, our plan of reorganization, the confirmation order and California law. The CPUC settlement agreement includes a statement of intent that as a result of the CPUC settlement agreement and our plan of reorganization, retail electricity rates will be reduced in January 2004 with future reductions expected thereafter.

The CPUC will set our capital structure and authorized return on equity in our annual cost of capital proceedings in its usual manner. However, from January 1, 2004 until Moody s has issued an issuer rating for us of not less than A3 or Standard & Poor s has issued a long-term issuer credit rating for us of not less than A-, our authorized return on equity will be no less than 11.22% per year and our authorized equity ratio for ratemaking purposes will be no less than 52%, except that for 2004 and 2005, our authorized equity ratio will equal the greater of the proportion of equity in the forecast of our average capital structure for calendar years 2004 and 2005 filed in our cost of capital proceedings and 48.6%.

Dismissal of Filed Rate Case, Other Litigation and Proceedings

On or as soon as practicable after the later of the effective date of our plan of reorganization and the date on which CPUC approval of the CPUC settlement agreement is no longer subject to appeal, we will dismiss with prejudice the case described in the section of this prospectus titled Business Legal Proceedings Pacific Gas and Electric Company vs. Loretta M. Lynch et al. (addressing the federal filed rate doctrine), withdraw the original plan of reorganization and dismiss other pending proceedings. In exchange, on or before January 1, 2004, the CPUC would establish and authorize the collection of the regulatory asset and our rate base for our electricity generation, and, on or as soon as practicable after the effective date, resolve phase 2 of the pending annual transition cost proceeding in which the CPUC is reviewing the reasonableness of our energy crisis purchase costs, with no adverse impact on our cost recovery as requested.

On or as soon as practicable after the later of the effective date of our plan of reorganization and the date on which CPUC approval of the CPUC settlement agreement is no longer subject to appeal, we, Corp and the CPUC will execute mutual releases and dismissals with prejudice of specified claims, actions or regulatory proceedings arising out of or related in any way to the energy crisis or the implementation of California s Assembly Bill 1890, or AB 1890, including the CPUC s investigation into past holding company actions during the California energy crisis (but only as to past actions, not prospective matters).

Withdrawal of Applications in Connection with the Original Plan of Reorganization

As required by the CPUC settlement agreement, we have requested a stay of all proceedings before the FERC, the NRC, the SEC and other regulatory agencies relating to approvals sought to implement the original plan of reorganization. We have also suspended all actions to obtain or transfer licenses, permits and franchises to implement the original plan of reorganization. On the effective date of our plan of reorganization or as soon thereafter as practicable, we and Corp will withdraw or abandon all applications for these regulatory approvals. In addition, we and Corp agreed that for the term of the regulatory asset neither we nor Corp, nor our respective affiliates, will make any filings under Sections 4, 5 or 7 of the Natural Gas Act to transfer ownership or ratemaking jurisdiction over our intrastate gas pipeline and storage facilities, which means that they will remain primarily subject to CPUC regulation. We and Corp also agreed that the CPUC has jurisdiction to review and approve any proposal to dispose of our property necessary or useful in the performance of our duties to the public.

Environmental Measures

We agreed to implement the following three environmental enhancement measures:

- we will encumber with conservation easements or donate approximately 140,000 acres of land to public agencies or non-profit conservation organizations;

- we will establish a California non-profit corporation to oversee the environmental enhancements associated with these lands and fund it with $70 million in cash over ten years, although we will be entitled to recover these payments in rates; and

- we will create a non-profit corporation funded with $15 million payable by us over five years dedicated to support research and investment in clean energy technology, primarily in our service territory.

Of the approximately 140,000 acres referred to in the first bullet, approximately 45,000 acres may be either donated or encumbered with conservation easements. The remaining land contains our or a joint licensee s hydroelectric generation facilities and may only be encumbered with conservation easements.

Waiver of Sovereign Immunity

The CPUC agreed to waive all existing and future rights of sovereign immunity, and all other similar immunities, as a defense in connection with any action or proceeding concerning the enforcement of, or other determination of the parties rights under, the CPUC settlement agreement, our plan of reorganization or the confirmation order. The CPUC also consented to the jurisdiction of any court or other tribunal or forum for those actions or proceedings, including the bankruptcy court. The CPUC s waiver is irrevocable and applies to the jurisdiction of any court, legal process, suit, judgment, attachment in aid of execution of a judgment, attachment before judgment, set-off or any other legal process with respect to the enforcement of, or other determination of the parties rights under, the CPUC settlement agreement, our plan of reorganization or the confirmation order. The CPUC settlement agreement contemplates that neither the CPUC nor any other California entity acting on its behalf may assert immunity in an action or proceeding concerning the parties rights under the CPUC settlement agreement, our plan of reorganization or the confirmation order.

Term and Enforceability

The CPUC settlement agreement generally terminates nine years after the effective date of our plan of reorganization, except that the rights of the parties to the CPUC settlement agreement that vest on or before termination, including any rights arising from any default under the CPUC settlement agreement, will survive termination for the purpose of enforcement. The parties agreed that the bankruptcy court will have jurisdiction over the parties for all purposes relating to enforcement of the CPUC settlement agreement, our plan of reorganization and the confirmation order. The parties also agreed that the CPUC settlement agreement, our plan of reorganization or any order entered by the bankruptcy court contemplated or required to implement the CPUC settlement agreement or our plan of reorganization will be irrevocable and binding on the parties and enforceable under federal law, notwithstanding any contrary state law or future decisions or orders of the CPUC.

Fees and Expenses

The CPUC settlement agreement provides that we would reimburse Corp and the CPUC for all of Corp s and the CPUC s respective professional fees and expenses incurred in connection with the Chapter 11 case once our plan of reorganization was confirmed. Of these amounts, the amounts reimbursed to the CPUC but not to Corp will be recovered from ratepayers over a reasonable time of up to four years.

Terms of Our Plan of Reorganization

The terms of the CPUC settlement agreement are reflected in our plan of reorganization, and the full CPUC settlement agreement is incorporated by reference into our plan of reorganization. Our plan of reorganization generally provides for payment in full of all allowed creditor claims (except for the claim of holders of pollution control bond-related obligations that will be reinstated) plus applicable interest on claims in certain classes and all cumulative dividends in arrears and mandatory sinking fund payments associated with our preferred stock. We will make these payments from the net proceeds from the initial offering of debt securities offered by this prospectus, other financings effected on or about the effective date of our plan of reorganization and cash on hand. We also will establish one or more escrow accounts for disputed claims and deposit cash into these accounts.

Under our plan of reorganization, timely asserted environmental, fire suppression, pending litigation and tort claims and workers compensation claims will pass through the Chapter 11 case unimpaired and will be satisfied by us in the ordinary course of business. However, all other valid undisputed claims against us as of the date the confirmation order was entered in the bankruptcy court will be satisfied, discharged and released in full on the effective date of our plan of reorganization. Subject to the provisions of the Bankruptcy Code, and in exchange for payments under our plan of reorganization, all persons and governmental entities are enjoined from asserting against us and our successors, or our or their assets or properties, any other or further claims or equity interests based upon any act or omission, transaction or other activity of any kind or nature that occurred before the confirmation date.

The disclosure statement was approved by the bankruptcy court on July 31, 2003, and votes on our plan of reorganization were solicited from holders of claims entitled to vote pursuant to a bankruptcy court-approved solicitation process which began on August 15, 2003. The confirmation hearing on our plan of reorganization began on , 2003 and our plan of reorganization was confirmed by the bankruptcy court on , 2003.

Conditions to the Effectiveness of Our Plan of Reorganization

Our plan of reorganization provides that it will not become effective unless and until each of the following conditions is satisfied or waived:

- the effective date occurs on or before March 31, 2004;
- all actions, documents and agreements necessary to implement our plan of reorganization are effected or executed;
- we and Corp have received all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions or documents that we and Corp determine are necessary to implement our plan of reorganization;
- our plan of reorganization has not been modified in a material way since the date of confirmation;
- we have consummated the sale of the debt securities provided for under our plan of reorganization;
- Moody s has issued an issuer rating for us of not less than Baa3 and Standard & Poor s has issued long-term issuer credit ratings for us of not less than BBB-;
- Moody s and Standard & Poor s have issued credit ratings for the debt securities provided for under our plan of reorganization of not less than Baa3 and BBB-, respectively;
- the CPUC has given final approval of the CPUC settlement agreement;
- we, Corp and the CPUC have executed and delivered the CPUC settlement agreement;
- the CPUC has given final approval for all of the financings, securities and accounts receivable programs provided for in our plan of reorganization; and
- the CPUC has given final approval for all rates, tariffs and agreements necessary to implement our plan of reorganization.

As described above, our plan of reorganization provides that it will not become effective unless and until the CPUC has given final approval of the CPUC settlement agreement, the financings, securities and accounts receivable programs provided for in our plan of reorganization, and all rates, tariffs and agreements necessary to implement our plan of reorganization. For purposes of these conditions, final approval means approval on behalf of the CPUC that is not subject to any pending appeal or further right of appeal, or approval on behalf of the CPUC that, although subject to a pending appeal or further right of appeal, has been agreed to by us and Corp to constitute final approval. Thus, the terms of our plan of reorganization would permit us and Corp to cause our plan of reorganization to become effective (and permit us to issue the debt securities offered by this prospectus) while the CPUC s approvals of the CPUC settlement agreement, the financings, securities and accounts receivable programs provided for in our plan of reorganization, and all rates, tariffs and agreements necessary to implement our plan of reorganization, are subject to pending appeals or further rights of appeal. In addition, our plan of reorganization provides that we may waive the conditions described under the first five bullets listed above.

BUSINESS

Our Company

We are a leading vertically integrated electricity and natural gas utility. We operate in northern and central California and are engaged in the businesses of electricity generation, electric transmission, natural gas transportation and storage, and electricity and natural gas distribution.

We have more customers than any other investor-owned utility in the United States. At December 31, 2002, we served approximately 4.8 million electricity distribution customers and approximately 3.9 million natural gas distribution customers in a service territory covering over 70,000 square miles. In 2002, we delivered approximately 78,230 GWh of electricity, which included approximately 7,400 GWh transmitted to direct access customers, and delivered approximately 790 Bcf of natural gas, which included approximately 508 Bcf of natural gas we did not purchase but which we transported on behalf of our customers.

We own, operate and control an extensive hydroelectric system in northern and central California and the Diablo Canyon nuclear power plant located near San Luis Obispo, California. At December 31, 2002, our electricity generation portfolio consisted of approximately 6,420 MW of owned generating capacity and approximately 5,698 MW of generating capacity under contract, for a combined generating capacity of approximately 12,118 MW. We are the largest non-governmental producer of hydroelectric power in the United States.

We own and operate an electric transmission system that comprises most of the high-voltage electric transmission lines and facilities in northern and central California. Our high-voltage transmission system consists of approximately 18,605 circuit miles of interconnected electric transmission lines and support facilities.

We also own and operate a natural gas pipeline and storage system that is interconnected to all the major natural gas supply basins in western North America. This system consists of approximately 6,300 miles of high-pressure pipelines that extend from the California-Oregon border to the California-Arizona border. The backbone transportation system consists of a northern pipeline system with a delivery capacity of approximately 2.0 Bcf per day and a southern pipeline system with a delivery capacity of approximately 1.1 Bcf per day.

Our Business Strengths

As a leading vertically integrated electricity and natural gas utility, we have the following business strengths:

Substantial Asset Base. At June 30, 2003, our total assets were approximately $26.0 billion, of which approximately $16.0 billion was net property, plant and equipment. We expect that our asset base will grow with future capital expenditures. As a regulated utility, our operating performance is tied to the size of our asset base. We believe that our substantial asset base will provide us with a stable source of revenue in the future.

Extensive and Highly Attractive Service Territory. We provide electricity and/or natural gas distribution services in 48 of California s 58 counties, which include most of northern and central California. We provide energy to approximately one out of 20 people in the United States. Our service territory has a large and diversified economy with a gross domestic product of approximately $561 billion in 2002, equivalent to the twelfth largest economy in the world.

Essential Service Provider. We perform an essential public service as the principal provider of electricity and natural gas distribution services, electric transmission services and natural gas transportation services in our service territory. In addition, for almost all our residential customers and most of our commercial and industrial customers, there are few commercially feasible alternative service providers.

Experienced Management Team and Employees. Our management and employees have substantial experience in the electricity and natural gas industries. We believe our management team s and employees years of experience and expertise in managing our infrastructure contribute significantly to our success.

Electricity Utility Operations

Electricity Distribution Operations

Our electricity distribution network extends throughout all or a part of 47 of California s 58 counties, comprising most of northern and central California. Our network consists of approximately 117,955 circuit miles of distribution lines (of which approximately 20% are underground and 80% are overhead) and 783 distribution substations, of which 417 are combined transmission and distribution substations.

Our distribution network interconnects to our electric transmission system at approximately 975 points. This interconnection between our 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 kV to 500 kV, to lower voltages, ranging from 4 kV to less than 60 kV, suitable for distribution to our customers. The distribution substations serve as the central hubs of our electricity distribution network 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 that link distribution lines and provide delivery to end-users. In some cases, we sell electricity from our distribution lines or facilities to entities, such as municipal and other utilities, that then resell the electricity.

The following chart shows the percentage of our total 2002 electricity deliveries represented by each of our major customer classes:

2002 ELECTRICITY DELIVERIES

(78,230 GWhs)

Electricity Distribution Operating Statistics

The following table shows our operating statistics (excluding subsidiaries) for electricity 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	12	14
Total	4,759,422	4,756,164	4,645,960	4,599,238	4,536,341
Deliveries (in GWh):(1)					
Residential	27,435	26,840	28,753	27,739	26,846
Commercial	31,328	30,780	31,761	30,426	28,839
Industrial	14,729	16,001	16,899	16,722	16,327
Agricultural	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
Subtotal	78,230	78,373	81,923	79,230	77,884
DWR	(21,031)	(28,640)			
Total non-DWR electricity	57,199	49,733	81,923	79,230	77,884
Revenues (in millions):					
Residential(2)	$ 3,642	$ 3,365	$ 3,008	$ 2,962	$ 2,892
Commercial(2)	4,469	3,925	2,693	2,837	2,793
Industrial(2)	1,275	1,312	510	864	933
Agricultural(2)	532	521	386	392	351
Public street and highway lighting	73	60	43	49	51
Other electric utilities	10	39	26	16	50
Subtotal	10,001	9,222	6,666	7,120	7,070
DWR	(2,056)	(2,173)			
Miscellaneous	193	240	195	162	161
Regulatory balancing accounts	40	37	(7)	(50)	(40)
Total electricity operating revenues	$ 8,178	$ 7,326	$ 6,854	$ 7,232	$ 7,191
Other Data:					
	6,577	6,444	7,062	6,905	6,776

Average annual residential usage (kWh)					
Average billed revenues (cents per kWh):(2)					
Residential	13.27	12.54	10.46	10.68	10.77
Commercial	14.26	12.75	8.48	9.32	9.69
Industrial	8.66	8.20	3.02	5.17	5.72
Agricultural	13.30	12.73	10.11	10.48	11.42
Net plant investment per customer	$ 2,105	$ 2,018	$ 1,969	$ 2,388	$ 2,705

(1) These amounts include electricity provided to direct access customers who procure their own supplies of electricity.

(2) Revenues and average billed revenues reflect reduction for direct access credits.

Electricity Resources

The following chart shows the percentage of our customers total 2002 electricity resources represented by each major electricity resource:

2002 ELECTRICITY RESOURCES

To the extent the electricity available from DWR allocated contracts, our generation facilities and our power purchase arrangements exceeds our customers demand, whether at non-peak times or otherwise, we sell the surplus into the wholesale electricity market. To the extent the electricity available from DWR allocated contracts, our generation facilities and our power purchase arrangements is not sufficient to meet our customers demand, whether at peak times or otherwise, we purchase the shortfall from the wholesale electricity market.

Generation Facilities

At December 31, 2002, we owned and operated the following generation facilities, all located in California, listed by energy source:

Generation Type	County Location	Number of Units	Net Operating Capacity (MW)
Hydroelectric:			
Conventional	16 counties in northern and central California	107	2,684
Helms pumped storage	Fresno	3	1,212
Hydroelectric subtotal		110	3,896
Fossil fuel:			
Humboldt Bay	Humboldt	2	105
Hunters Point(1)	San Francisco	2	215
Mobile turbines	Humboldt	2	30
Fossil fuel subtotal		6	350
Nuclear:			
Diablo Canyon	San Luis Obispo	2	2,174
Total		118	6,420

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

Hydroelectric Generation Facilities. Our 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 Power Plant. Our Diablo Canyon power plant consists of two nuclear power reactor units, each capable of generating up to approximately 26 million kWh of electricity per day. Unit 1 began commercial operation in May 1985 and the operating license for this unit expires in September 2021. Unit 2 began commercial operation in March 1986 and the operating license for this unit expires in April 2025. For the ten-year period ended December 31, 2002, our Diablo Canyon power plant achieved an operating capacity factor of approximately 88%.

The following table outlines our Diablo Canyon power plant s refueling schedule for the next five years. Diablo Canyon power plant 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, which is the plant s average refueling outage over the last five years. This schedule also assumes outages of up to 80 days for non-refueling tasks, which include steam generator inspection and repair, low pressure turbine rotor replacement, and the first of two proposed steam generator replacements. During a routine inspection conducted as part of the plant s last refueling of Unit 2 in February 2003, we found indications of steam generator tube cracking in locations not previously detected. We restarted Unit 2 with the NRC s approval and believe we have technical justification to operate without further steam generator inspection until the next scheduled refueling in the fall of 2004. The actual outage periods will depend on the scope of the work required for a particular outage and other factors. The schedule is subject to change in the event of unscheduled plant outages.

	2004	2005	2006	2007	2008
Unit 1					
Refueling	March	October		April	
Duration (days)	48	40-45		35	
Startup	May	November		May	
Unit 2					
Refueling	October		April		February
Duration (days)	40		40-45		80
Startup	December		May		April

We also are planning to accelerate the replacement of the second steam generator to 2009.

DWR Power Purchases

As a result of the California energy crisis, in 2001, the State of California authorized the DWR to purchase electricity to satisfy the difference between the aggregate electricity demand of the customers of the California investor-owned utilities and the electricity those utilities had available for delivery from generation facilities and power purchase arrangements. California s Assembly Bill 1X, or AB 1X, passed in February 2001, authorized the DWR to enter into contracts for the purchase of electricity and to issue revenue bonds to finance electricity purchases. Consistent with applicable law and CPUC orders, we and other California investor-owned electric utilities act as the billing and collection agent for the DWR s sales of electricity to retail customers. Electricity from DWR allocated contracts represented approximately 25% of our total sources of electricity in 2002.

In January 2003, we became responsible for scheduling and dispatching the electricity subject to the 19 DWR allocated contracts on a least-cost basis. Of these contracts, a total average capacity for 2003 of approximately 2,600 MW is subject to must take contracts, which require the DWR to take and pay for the electricity regardless of need. A total average capacity for 2003 of approximately 1,800 MW is subject to contracts which require the DWR to pay a capacity charge but do not require the purchase of a firm amount of electricity. Energy payments are due only for the power actually delivered. The DWR is currently legally and financially responsible for these contracts.

The DWR has stated publicly that it intends to transfer full legal title to, and responsibility for, the DWR allocated contracts to the California investor-owned utilities as soon as possible. However, the DWR allocated contracts cannot be transferred to us without the consent of the CPUC. The CPUC settlement agreement provides that the CPUC will not require us to accept an assignment of, or to assume legal or financial responsibility for, the DWR allocated contracts unless each of the following conditions has been met:

- after assumption, our issuer rating by Moody s will be no less than A2 and our long-term issuer credit rating by Standard & Poor s will be no less than A;

the CPUC first makes a finding that the DWR allocated contracts being assumed are just and reasonable; and

the CPUC has acted to ensure that we will receive full and timely recovery in our retail electricity rates of all costs associated with the DWR allocated contracts without further review.

The CPUC settlement agreement does not limit the CPUC s discretion to review the prudence of our administration and dispatch of the DWR allocated contracts consistent with applicable law.

Third Party Agreements

Qualifying Facility Agreements. We are required by CPUC decisions and the Public Utility Regulatory Policies Act of 1978, or PURPA, to purchase energy and capacity from independent power producers that are qualifying facilities under PURPA. Under PURPA, the CPUC required California utilities to enter into a series of qualifying facility long-term power purchase agreements and approved the applicable terms, conditions, price options and eligibility requirements. These agreements require us to pay for energy and capacity. Energy payments are based on the qualifying facility s actual electricity output and capacity payments are based on the qualifying facility s contractual capacity commitment. Capacity payments may be adjusted if the facility fails to meet or exceeds performance requirements specified in the applicable power purchase agreements.

At December 31, 2002, we had agreements with 285 qualifying facilities for approximately 4,200 MW. The 4,200 MW consists 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 dates and will terminate only when the owner of the qualifying facility exercises its termination option. Qualifying facility power purchase agreements accounted for approximately 25% of our 2002 electricity sources and no single qualifying facility accounted for more than 5% of our 2002 electricity sources. Currently pending federal energy legislation would revise or repeal a portion of the obligations of public utilities to purchase energy from qualifying facilities under PURPA. While it is unclear how a revision or repeal of a portion of PURPA would affect our procurement policies in the future because of the prospective nature of proposals to alter PURPA, our currently effective qualifying facility power purchase agreements would not be affected by the pending federal energy legislation.

Renewable Energy Contracts. In June 2003, the CPUC issued a decision pursuant to SB 1078 that adopts the framework for a renewable energy portfolio standard requiring each California investor-owed utility to increase purchases of renewable energy by at least 1% of its retail sales per year. By the end of 2017, we must purchase at least 20% of our total electricity from renewable resources. Under SB 1078, we were not obligated to purchase additional renewable energy until we received an investment grade credit rating. However, under subsequently enacted SB 67, we may be required to purchase additional renewable energy once we are able to do so on reasonable terms and the renewable energy contracts will not impair the restoration of our creditworthiness. Until that time, we will accumulate an APT based on 1% of annual retail sales. When we receive an investment grade credit rating or the CPUC determines that the SB 67 requirements are satisfied, we expect to enter into purchase contracts for renewable energy to meet our accumulated APT.

We currently estimate the annual 1% increase in renewable resource electricity in our portfolio will initially require between 80 and 100 MW of additional renewable capacity to be added per year. The CPUC approved offers we submitted that were sufficient to meet our 2003 renewable energy requirement in December 2002. Pursuant to this approval, we have entered into three contracts with renewable energy suppliers that include both capacity and energy payments. During 2003, electricity under the contracts is sold by the suppliers to the DWR, which resells the electricity to our customers. We expect to reimburse the DWR for the contract costs. After 2003 and once certain conditions are met, we will become obligated under the contracts for the remainder of their five-year terms. We have submitted to the CPUC for approval several contracts intended to meet our 2004 renewable energy requirement.

Other Third Party Power Agreements. We also have contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, we must make specified semi-annual minimum payments based on the irrigation districts and water agencies debt service requirements, whether or not any hydroelectric power is supplied (so long as the supplier retains its FERC authorization) and variable payments for operation, maintenance and debt service costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. Our irrigation district and water agency contracts in the aggregate accounted for approximately 4% of our 2002 electricity sources.

We also have two other third party power purchase agreements representing an aggregate of 450 MW, both of which expire at the end of 2003. Our minimum payments due under these contracts are $196 million for 2003.

Annual Receipts and Payments. The amount of electricity received and the total payments made under qualifying facility, irrigation district, water agency and bilateral agreements during 1998 through 2002 were as follows:

	2002	2001	2000	1999	1998
Gigawatt hours received	28,088	23,732	26,027	25,910	25,994
Qualifying facility energy payments (in millions)	$ 1,051	$ 1,454	$ 1,549	$837	$943
Qualifying facility 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 (in millions)	$ 196	$ 155	$ 53	$	$

Western Area Power Administration

In 1967, we entered into several long-term power contracts with WAPA governing the interconnection of our transmission system with WAPA s transmission system, WAPA s use of our transmission and distribution system, and the integration of our loads and resources with WAPA s loads and resources. These contracts give us access to WAPA s excess hydroelectric power and obligate us to provide WAPA with electricity when its resources are not sufficient to meet its requirements. These contracts terminate on December 31, 2004.

As a result of California s electricity industry restructuring in 1998, we were required to purchase the electricity that we needed to meet our own and WAPA s requirements from the PX. This caused us to be exposed to market based energy pricing rather than the cost of service based electricity pricing that had been contemplated when the contracts were executed. For the period from January 1, 2000 through December 31, 2002, we paid an estimated $882 million more for the electricity we purchased on behalf of WAPA than we received for our sales of electricity to WAPA. The cost to fulfill our obligations to WAPA under these contracts through their expiration in 2004 is uncertain. However, we expect that the cost of meeting our contractual obligations to WAPA will be greater than the amount that we receive from WAPA under the contracts. In part, the amount of electricity we will be required to deliver to WAPA depends on the amount of electricity available from WAPA s hydroelectric resources. Although it is not indicative of future sales commitments or sales-related costs, WAPA s net amount purchased from us was 3,619 GWh in 2002, 4,823 GWh in 2001 and 5,120 GWh in 2000. Given the recent decline in the market price for electricity, the lower forecasts of energy prices going forward and the expected increased output of WAPA hydroelectric generation facilities, we expect that the cost of meeting our contractual obligations to WAPA will be significantly less in the future than it was in 2002, 2001 and 2000.

The parties are in the process of negotiating a successor arrangement to the WAPA contracts, which will be filed with the FERC for approval. We currently contemplate that the successor arrangement will provide for interconnection through which WAPA may obtain its transmission and electricity requirements from the ISO. We currently estimate that we will file our proposal with the FERC in January 2004.

Electricity Transmission

At December 31, 2002, we owned approximately 18,605 circuit miles of interconnected transmission lines operated at voltages of 60 kV to 500 kV and transmission substations with a capacity of approximately 47,596 MVA. Electricity is transmitted across these lines and substations and is then distributed to customers through approximately 118,033 circuit miles of distribution lines and substations with a capacity of approximately 24,020 MVA. In 2002, we delivered approximately 78,230 GWh to our customers, including approximately 7,400 GWh delivered to direct access customers. We are interconnected with electric power systems in the Western Electricity Coordinating Council, or WECC, which includes 14 western states, Alberta and British Columbia, Canada, and parts of Mexico.

In connection with electricity industry restructuring, the California investor-owned utilities relinquished control, but not ownership, of their transmission facilities to the ISO in 1998. The FERC has jurisdiction over these transmission facilities, and the revenue requirements and rates for transmission service are set by the FERC. The ISO, which is 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 maintaining the reliability of the transmission system.

We have been working closely with the ISO to continue expanding the capacity on our electric transmission system. For instance, WAPA and an independent transmission company, Trans Elect NTD, Inc., are constructing a new 500 kV line to expand one segment of the transmission system known as Path 15, which is located in the southern portion of our 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 electricity intended to be transmitted between northern California and southern California. This transmission constraint historically has resulted in significant wholesale electricity price differentials between northern and southern California, with relatively high electricity prices in northern California and relatively low electricity prices in southern California. Transmission constraints in this area coupled with a lack of available generation in northern California resulted in rotating outages in northern California twice during the winter of 2001. We will interconnect the new 500 kV line at our existing substations at the line terminals and reconfigure our 230 kV and 115 kV facilities in the area to support a higher transfer capability through this section of the grid. This new 500 kV line is expected to be operational in the fall of 2004.

Nuclear Insurance

We have several types of nuclear insurance for our nuclear power plants. We have $2.75 billion of property insurance coverage and $490 million of business interruption insurance coverage as a member of NEIL. NEIL is a mutual insurer owned by utilities with nuclear facilities. Under this insurance, if any nuclear generation facility insured by NEIL suffers a catastrophic loss causing a prolonged accidental outage, we may be required to pay additional annual premiums of up to $36.7 million.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. If one or more acts of domestic terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member within a 12-month period, the maximum recovery under all those nuclear insurance policies may not exceed $3.24 billion plus the additional amounts recovered by NEIL for these losses from reinsurance. Under the Terrorism Risk Insurance Act of 2002, NEIL would be entitled to receive substantial proceeds from reinsurance coverage for an act caused by foreign terrorism. The Terrorism Risk Insurance Act of 2002 expires on December 31, 2005.

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to $10.9 billion. As required by the Price-Anderson Act, we have purchased the maximum available public liability insurance of $300 million for our Diablo Canyon power plant. The balance of the $10.9 billion of liability protection is covered by a loss-sharing program among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of reactors of 100 MW or higher. If a nuclear incident results in costs in excess of $300 million, then we may be responsible for up to $100.6 million per reactor, with payments in each year limited to a maximum of $10 million per incident until we have fully paid our share of the liability. Since our Diablo Canyon power plant has two nuclear reactors of over 100 MW, we may be assessed up to $201.2 million per incident, with payments in each year limited to a maximum of $20 million per incident.

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

Gas Utility Operations

We own and operate an integrated natural gas transportation, storage and distribution system in California that extends throughout all or a part of 38 of California s 58 counties and includes most of northern and central California. In 2002, we served approximately 3.9 million natural gas distribution customers. The total volume of natural gas throughput during 2002 was approximately 790 Bcf.

At December 31, 2002, our system consisted of approximately 6,300 miles of transportation pipelines, three gas storage facilities and approximately 38,944 miles of gas distribution lines. Our distribution network connects to our transportation and storage system at approximately 2,200 major interconnection points. Our Line 400/ 401 interconnects with GTN s natural gas transportation system at the Oregon-California border. Our Line 400/ 401 has a receipt capacity at the border of approximately 2.0 Bcf per day. Our Line 300, which interconnects to the U.S. southwest and Rocky Mountain pipeline systems owned by third parties (Transwestern, El Paso, Questar Southern Trails Pipeline Company and Kern River Pipeline Company), has a receipt capacity at the California-Arizona border of approximately 1.1 Bcf per day.

We also own and operate three underground natural gas storage fields located along our transportation and storage system in California in close proximity to 90% of our end-user demand. These fields have a combined annual cycle capacity of approximately 40 Bcf. In addition, two independent storage operators are interconnected to our transportation system in northern California.

Through interconnection with other interstate pipelines, we 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 our 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 our total customers and 36% of our total natural gas deliveries, while noncore customers comprised less than 1% of our total customers and 64% of our total natural gas deliveries.

We provide natural gas delivery services to all core and noncore customers connected to our system in our service territory. Core customers can purchase natural gas from alternate energy service providers or can elect to have us provide both delivery service and natural gas supply. Where we provide both supply and delivery, we refer to the service as natural gas bundled service. Currently, over 99% of core customers, representing over 98% of core market demand, choose to receive natural gas bundled services from us.

We offer transportation, distribution and storage services as separate and distinct services to our noncore customers. These customers have the opportunity to select from a menu of services offered by us and to pay only for the services that they use. Noncore customers formerly were able to subscribe for natural gas bundled service as if they were core customers but are no longer allowed to do so. Access to our transportation system is possible for all gas marketers and shippers, as well as noncore customers.

Customers pay a distribution rate that reflects our costs to serve each customer class. We have regulatory balancing accounts for core customers designed to ensure that our 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 our natural gas distribution base revenues are recovered from core customers and 3% are recovered from noncore customers. The amended Gas Accord II application requests balancing account treatment for noncore gas distribution revenues.

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 electricity and gas utilities. The 2002 California Gas Report updated our annual natural gas requirements forecast for the years 2002 through 2022, forecasting average annual growth in our gas deliveries of approximately 1.8%. The natural 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 the amount and location of electricity generation.

The following chart shows the percentage of our total 2002 natural gas deliveries represented by each of our major customer classes:

2002 NATURAL GAS DELIVERIES

(790 Bcf)

Note: Deliveries to industrial and other gas utilities, which amounted to less than 1% of total deliveries in 2002, are not included in the chart.

Natural Gas Operating Statistics

The following table shows our operating statistics from 1998 through 2002 for natural 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 (MMcf):					
Purchased from suppliers in:					
Canada	210,716	209,630	216,684	230,808	298,125
California	19,533	20,352	32,167	18,956	17,724
Other states	67,878	76,589	75,834	107,226	122,342
Total purchased	298,127	306,571	324,685	356,990	438,191
Net (to storage) from storage	(218)	(27,027)	19,420	(980)	(14,468)
Total	297,909	279,544	344,105	356,010	423,723
Utility use, losses, etc.(1)	(16,393)	(8,988)	(62,960)	(47,152)	(129,305)
Net gas for sales	281,516	270,556	281,145	308,858	294,418
Bundled gas sales (MMcf):					
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		13	41	28	14
Total	281,516	270,556	281,145	308,858	294,418
Transportation only (MMcf):	508,090	646,079	606,152	484,218	396,872
Revenues (in millions):					
Bundled gas sales:					
Residential	$ 1,379	$ 2,308	$ 1,681	$ 1,543	$ 1,414
Commercial	499	783	513	449	426
Industrial	3	16	35	24	25
Other gas utilities	1				1
Bundled gas revenues	1,882	3,107	2,229	2,016	1,866
Transportation service only revenue	316	375	338	287	274
Miscellaneous	127	(93)	84	(47)	42
Regulatory balancing accounts	11	(253)	132	(260)	(448)
Operating revenues	$ 2,336	$ 3,136	$ 2,783	$ 1,996	$ 1,734
Selected Statistics:					
Average annual residential usage (Mcf)	54	53	59	65	63
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	0.62	0.58	0.56	0.59	0.69
Net plant investment per customer	$ 1,006	$ 970	$ 1,003	$ 1,011	$ 1,040

(1) Includes fuel for our fossil fuel-fired generation plants.

Natural Gas Supplies

We purchase natural gas directly from producers and marketers in both Canada and the United States to serve our core customers. The contract lengths and natural gas sources of our portfolio of natural gas purchase contracts have fluctuated, generally based on market conditions. During 2002, we purchased approximately 298,127 MMcf of natural gas from approximately 54 suppliers. Substantially all this supply was purchased under contracts with a term of less than one year. Our largest individual supplier represented approximately 9.4% of the total natural gas volume we purchased during 2002.

The following table shows the total volume and average price of natural gas in dollars per Mcf of our natural gas purchases by region during each of the last five years.

	2002		2001		2000		1999		1998	
	MMcf	Avg. Price(1)	MMcf	Avg. Price(1)	MMcf	Avg. Price(1)	MMcf	Avg. Price(1)	MMcf	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	20,352	$11.55	32,167	$8.20	18,956	$2.45	17,724	$2.44
Other states (substantially all U.S. southwest)	67,878	$3.04	76,589	$10.41	75,835	$5.99	107,227	$2.42	122,342	$2.62
Total/weighted average	298,127	$2.59	306,571	$ 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 natural 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. After March 1, 1998, the average price for natural gas also includes intrastate pipeline demand and reservation charges. These costs previously were bundled in natural gas rates.

Under the CPIM, our purchase costs are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where we typically purchase natural gas. Costs that fall within a tolerance band, which is between 99% and 102% around the benchmark, are considered reasonable and fully recoverable, in customers rates. Currently, one-half of the costs outside the tolerance band are recoverable in our customers rates, and our customers receive the benefits of one-half of any savings outside the tolerance band in their rates. However, in June 2003, we reached a settlement with the ORA that, if approved by the CPUC, would increase the amount of savings passed through to ratepayers from one-half to three-fourths, retroactive to November 1, 2002. Under the settlement, ratepayers would continue to bear one-half of the costs incurred above the tolerance band.

Natural Gas Gathering Facilities

Our natural gas gathering system collects and processes natural gas from third-party wells in California. During 2002, approximately 6% of our natural gas supplies came from 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 150 MMcf per day of natural gas flows through our gas gathering system.

Interstate and Canadian Natural Gas Transportation Services Agreements

In 2002, approximately 71% of our natural gas supplies came from western Canada. We have a number of arrangements with interstate and Canadian third party transportation service providers to serve core customers service demands. We have 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 United States-Canada border where it enters GTN s transportation pipeline and is transported to southern Oregon. GTN s pipeline connects to our natural gas transportation system near Malin, Oregon.

During 2002, approximately 23% of our natural gas supplies came from the southwestern United States and the Rocky Mountains. We have firm transportation agreements with Transwestern and El Paso to transport this

natural gas to interconnections with our natural gas transportation system in the area of California near Topock, Arizona.

The following table shows certain information about our firm natural gas pipeline transportation agreements, including the contract quantities, contract durations and associated demand charges for capacity reservations. These agreements require us to pay fixed demand charges for reserving firm capacity on the pipelines. The total demand charges may change periodically as a result of changes in regulated tariff rates 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. We may recover these demand charges through the CPIM. We may, upon prior notice, extend each of these natural gas transportation contracts for additional minimum terms ranging, depending on the particular contract, from one to ten years. On the FERC-regulated pipelines, we have a right-of-first refusal allowing us to renew natural gas transportation agreements at the end of their terms. In the event another prospective shipper wanted the capacity, we would be required to match the competing bid with respect to both price and term.

Pipeline	Quantity MDth per day	Expiration Date	Demand Charges For the Year Ended December 31, 2002	Demand Charges For the Six Months Ended June 30, 2003
			(in millions)	
El Paso Natural Gas Company(1)	100	10/31/2003	$ 2.2	$ 6.6
El Paso Natural Gas Company(1)	64	12/31/2004	$ 0.8	$ 2.4
TransCanada NOVA Gas Transmission, Ltd.	593	12/31/2004	$23.5	$11.9
TransCanada PipeLines Ltd., B.C. System	584	10/31/2005	$10.5	$ 5.3
PG&E Gas Transmission, Northwest Corporation	610	10/31/2005	$45.4	$28.5
Transwestern Pipeline Co.	150	03/31/2007	$20.9	$10.5
El Paso Natural Gas Company(1)	40	03/31/2007	$ 0.7	$ 2.2

(1) Commenced November 1, 2002.

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 and facilities necessary to purchase, 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 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 have faced intensifying pressures to unbundle, or price separately, those services that are no longer considered natural monopolies. The most significant of these are the commodity components the supply of 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 forces 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 Electricity Industry

The FERC s policies have supported the development of a competitive electricity generation industry. FERC 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 regional transmission organizations and advanced the view that a regulated, unbundled transmission sector should facilitate competition in both wholesale electricity generation and retail electricity markets. The FERC s more recent standard market design proposal continues to uphold this view. The FERC s regional transmission organization policy and standard market design rulemaking may be affected by energy legislation pending before Congress.

In 1998, California implemented AB 1890, which mandated the restructuring of the California electricity industry and established a market framework for electricity generation in which generators and other electricity providers were permitted to charge market-based prices for wholesale electricity while the retail electricity rates we and the other California investor-owned utilities charged our customers were frozen. See Electricity Ratemaking Overview below.

AB 1890 also gave customers the choice of continuing to buy electricity from the California investor-owned utilities or, beginning in April 1998, becoming direct access customers. The CPUC suspended the right of retail end-user customers to become direct access customers on September 20, 2001. This prevented additional customers from entering into contracts to purchase electricity from alternate energy service providers after that date. The CPUC has assessed the CRS on direct access customers to avoid a shift of costs from direct access customers to customers who receive bundled service.

Further, in October 2003, the CPUC instituted a rulemaking implementing AB 117, which permits California cities and counties to purchase and sell electricity for their residents once they have registered as community choice aggregators. Under AB 117, we would continue to provide distribution, metering and billing services to the community choice aggregators customers and be those customers provider of electricity of last resort. However, once registration has occurred, each community choice aggregator would procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from us. To prevent a shifting of costs to customers of a utility who receive bundled services, AB 117 requires the CPUC to determine a cost-recovery mechanism so that retail end-users of the community choice aggregator will pay an appropriate share of DWR costs and certain of that utility s costs that are fixed and unavoidable.

We face increased competition in the electricity distribution business as a result of the construction of duplicate distribution facilities to serve specific existing or new customers, municipalization of our distribution facilities by local governments or districts, self-generation by our customers, and other forms of competition that may result in stranded investment capital, loss of customer growth and additional barriers to cost recovery. As customers and local public officials explore their energy options in light of the recent California energy crisis, these bypass risks may be increasing and may increase further if our rates exceed the cost of other available alternatives.

A number of local governments and districts in California are considering various forms of municipalization. The City and County of San Francisco and the City of Davis (along with other California communities) have been considering municipalization of our electricity distribution system within their jurisdictions. In addition, the Sacramento Municipal Utility District is currently considering annexing portions of our service territory, which would allow the municipality to compete with us. Some existing public power entities, such as the Modesto and Merced Irrigation Districts, also are expanding their services in competition with us. Finally, some districts that are not currently distributing electricity, including the El Dorado Irrigation District and the South San Joaquin Irrigation District, are considering building facilities that would duplicate our facilities. In May 2003, the South San Joaquin Irrigation District revealed its plans to invest over $40 million to duplicate our distribution facilities and begin serving existing and new customers in and around Manteca. In 2002, the City of Hercules formed its own municipal utility for the purpose of competing with us to serve new customers within the city. In 2003, the City of Hercules began providing electricity service to a 200-home subdivision, and has been actively pursuing additional residential and commercial customers. We cannot currently predict the impact of these actions on our business, although one possible outcome is a decline in the demand for the electricity that we provide, which would result in a corresponding decline in our revenues.

In addition, technological developments could result in the development of economically attractive alternatives to purchasing electricity through our distribution facilities. If the number of our customers declines due to these forms of competition and our rates are not adjusted in a timely manner to allow us to fully recover our investment and procurement costs, our financial condition and results of operations would be materially adversely affected.

The Natural Gas Industry

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

In 1998, we implemented the Gas Accord under which the natural gas transportation and storage services we provide were separated for ratemaking purposes from our distribution services. The Gas Accord changed the terms of service and rate structure for natural gas transportation, allowing our core customers to purchase natural gas from competing suppliers. Our industrial and larger commercial customers, or noncore customers, purchase their natural gas from producers, marketers and brokers and purchase their preferred mix of transportation, storage and distribution from us. Although they can select the gas supplier of their choice, substantially all core customers buy natural gas as well as transportation and distribution services from us as bundled service.

We compete with other natural gas pipeline companies for customers transporting gas 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 our market share for transportation of natural gas to the southern California market is the total delivered cost of western Canadian natural gas relative to the total delivered cost of natural gas from the southwestern United States and Rocky Mountains. The total delivered cost of natural gas includes, in addition to the commodity cost, transportation costs on all pipeline systems that are used to deliver the natural gas which, in our case, includes the cost of transportation of the natural gas from Canada to the California border and the cost of our transportation system from the border to southern California. In general, when the total cost of western Canadian natural gas increases relative to other competing natural gas sources, our market share of transportation services into southern California decreases. In addition, Kern River Pipeline Company completed a major expansion of its pipeline system in May 2003 that increased its capacity to deliver natural gas into the southern California market by approximately 900 MMcf per day. As a result of Kern River Pipeline Company s expansion, the volume of natural gas that we deliver to the southern California market may decrease. We also compete for storage services with other third party storage providers, primarily in northern California. The most important competitive factors affecting our market share for storage services 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 electricity generation natural gas demands in late 2000 and 2001 spurred several new natural gas pipeline proposals for northern and central California, many of the electricity 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.

Employees

At June 30, 2003, we had 19,819 employees. Of these 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 ESC and IBEW collective bargaining agreements expire on December 31, 2007. The IUSO collective bargaining agreement expires on February 28, 2006.

Properties

Our corporate headquarters consist of approximately 1.8 million square feet of office space located in several buildings in San Francisco, California. In addition to this corporate office space, we own or have obtained the right to occupy and/or use real property comprising our electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, all of which are described above under Electricity Utility Operations and Gas Utility Operations. In total, we occupy 9.3 million square feet, including 975,000 square feet of leased office space. We occupy or use real property that we do not own primarily through various leases, easements, rights-of-way, permits or licenses from private landowners or governmental authorities. We currently own approximately 170,000 acres of land, approximately 140,000 acres of which we will encumber with conservation easements or donate to public agencies or non-profit conservation organizations under the CPUC settlement agreement. Approximately 45,000 acres of this land may be either donated or encumbered with conservation easements. The remaining land contains our or a joint licensee s hydroelectric generation facilities and may only be encumbered with conservation easements.

Our Regulatory Environment

Various aspects of our business are subject to a complex set of energy, environmental and other governmental laws, regulations and regulatory proceedings at the federal, state and local levels. This section and the Ratemaking section which follows summarize some of the more significant energy laws, regulations and regulatory proceedings affecting our business at this time. They are not an exhaustive description of all the energy laws, regulations and regulatory proceedings that affect us. We cannot assure you that, in the future, these energy laws, regulations and regulatory proceedings will not change or be implemented or applied in a way that we do not currently anticipate. The discussion below includes certain forward-looking statements that reflect our current estimates. These estimates are subject to periodic evaluation and revision. Future estimates and actual results may differ materially from our current expectations.

Federal Energy Regulation

The FERC

The FERC is an independent agency within the DOE that regulates 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, tariffs and conditions of service of the ISO and the terms and rates of wholesale electricity sales. The ISO is responsible 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. In addition, the FERC has jurisdiction over our electric transmission revenue requirements and rates, the licensing of our hydroelectric generation facilities and the interstate sale and transportation of natural gas.

The FERC s policies have supported the development of a competitive electricity generation industry. FERC 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 regional transmission organizations and advanced the view that a regulated, unbundled transmission sector should facilitate competition in both wholesale electricity generation and retail electricity markets. The FERC s more recent standard market design proposal continues to uphold this view. The FERC s regional transmission organization policy and standard market design rulemaking may be affected by energy legislation pending before Congress.

On July 24, 2003, the FERC issued a final rule on the interconnection of generators larger than 20 MW that will require regulated transmission providers generally to use standard interconnection procedures and a standard agreement for generator interconnections. The generator interconnection rules would require us to revise the agreements and procedures followed when constructing facilities to interconnect new generators. Under this rule, generators in our service territory will generally be responsible for initially funding the costs of these interconnection facilities. However, unless the ISO presents an alternative acceptable to the FERC, generators will be entitled to a credit for the cost of network upgrades that they funded. In separate rulings, the FERC also has extended this approach to generators with agreements that have previously been accepted by the FERC which directly assigned to the generators responsibility for the cost of those upgrades. We expect to recover over time in our rates the refunds provided to the generators as a result of these credits. Numerous parties have requested rehearing and a stay of the generator interconnection rule. The FERC recently stayed the effect of the final rule until January 2004 and indicated that it intends to act on the pending rehearing dates before the effective date of the final rule. Energy legislation pending before Congress may affect portions of the FERC generator interconnection rulemaking.

In response to the unprecedented increase in wholesale electricity prices during the California energy crisis, the FERC issued a series of orders in the spring and summer of 2001 and July 2002 aimed at prospectively mitigating extreme wholesale energy prices like those that prevailed in 2000 and 2001. These orders established a cap on bids for real-time electricity and ancillary services of $250 per MWh and established various automatic mitigation procedures. Recently, in the FERC s notice of proposed rulemaking on standard market design, 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. FERC will consider ISO market monitoring together with market-based rate conditions to be adopted in February 2004.

Various entities, including us and the State of California, are seeking up to $8.9 billion in refunds for electricity overcharges during the California energy crisis on behalf of electricity purchasers. On December 12, 2002, a FERC administrative law judge issued an initial decision finding that power suppliers overcharged the California investor-owned utilities, the State of California, and other buyers by $1.8 billion from October 2, 2000 to June 2001 (the only time period for which the FERC permitted refund claims), but that California buyers still owe the power suppliers $3.0 billion, leaving $1.2 billion in net unpaid bills.

In March 2003, the FERC confirmed most of the administrative law judge s findings, but partially modified the refund methodology established by the administrative law judge. In October 2003, the FERC issued a decision confirming the modified refund methodology contained in the March 2003 order. The modified refund methodology included use of a new natural gas price methodology as the basis for mitigated prices and directed the ISO and PX to make compliance filings establishing refund amounts by March 2004. Under the CPUC settlement agreement, we and Corp agreed to continue to cooperate with the CPUC and the State of California in seeking refunds from generators and other energy suppliers. The net after-tax amount of any refunds, claim offsets, or other credits from generators or other energy suppliers relating to PX, ISO, qualifying facilities or energy service provider costs that we actually realize in cash or by offset of creditor claims in the Chapter 11 case shall be applied by us to reduce the outstanding balance of the $2.21 billion after-tax regulatory asset created by the CPUC settlement agreement, dollar for dollar. See the section of this prospectus titled Description of Our Plan of Reorganization The CPUC Settlement Agreement Principal Terms Regulatory Asset.

We have recorded $1.8 billion of claims filed by various electricity generators in our Chapter 11 case as liabilities subject to compromise. We currently estimate that these claims would have been reduced to approximately $1.2 billion based on refund methodology recommended in the administrative law judge s initial decision. The recent recalculation of market prices according to the modified methodology adopted by the FERC could result in a reduction of several hundred million dollars in the amount of the suppliers claims. However, this reduction could be offset by the amount of any additional fuel cost allowance for suppliers if they provide evidence that natural gas prices were higher than the natural gas prices assumed in the refund methodology accepted by the FERC.

On June 25, 2003, the FERC issued a series of orders directing more than 40 companies to show cause why they should not disgorge profits for a variety of violations of the ISO and PX tariffs related to market manipulation during the summer of 2000. We were one of the companies named in these orders. As to those allegations relating to us, we have submitted information to the FERC showing that some transactions were misidentified and do not relate to us, and that other identified transactions did not constitute improper behavior, but rather were justifiable under the then-existing operational circumstances. The FERC staff is expected to determine before November 3, 2003 whether it will continue to investigate us in light of our explanations. Due to the limited dollar amount of our transactions identified as possibly in violation of the tariffs, we do not expect the outcome to have a material adverse impact on our financial condition or results of operations.

The FERC, also in June 2003, began an investigation of why companies should not disgorge profits related to bidding for electricity in violation of ISO and PX tariffs during the period from May 1 through October 1, 2000. We submitted information explaining our bidding, which was designed to ensure optimal dispatch of our resources, including when and at what level we operated our hydroelectric generation facilities. Since we were a net purchaser of electricity during this period, we expect that the amount we would be required to pay, if any, would be offset by the refunds we would receive from other companies. Assuming we receive refunds from other companies, we do not expect the outcome to have a material adverse impact on our financial condition or results of operations. This proceeding is being conducted as a FERC staff investigation and results are not expected until the first quarter of 2004.

In addition, the CPUC has opened a proceeding to examine whether the amounts paid to qualifying facilities during the California energy crisis reflected dysfunctional market conditions that warrant a refund of a portion of those payments.

The NRC

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including our Diablo Canyon power plant and Humboldt Bay Unit 3. NRC regulations require extensive monitoring and review of the safety, radiological, environmental and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of the nuclear plant, or both. Safety requirements promulgated by the NRC have, in the past, necessitated substantial capital expenditures at our Diablo Canyon power plant and additional significant capital expenditures could be required in the future.

Other Regulation

Federal energy legislation currently pending before Congress would, among other things, repeal the Public Utility Holding Company Act of 1935, or PUHCA. PUHCA currently imposes significant regulatory barriers to mergers and acquisitions involving public utilities and public utility holding companies. Thus the repeal of PUHCA could have the effect of triggering a period of consolidation among public utilities, as well as acquisitions of public utilities by other businesses. As a result, the repeal of PUHCA could have the effect of increasing competitive pressures in our industry, and increasing competition in our industry from sources we do not currently view as competitors. The effective date proposed for PUHCA repeal as well as the effective date for proposed legislation that would replace PUHCA is December 1, 2004. Under the proposed legislation that would replace PUHCA, public utilities and public utility holding companies would remain under the regulatory oversight of FERC, but not the SEC, as is currently the case.

We obtain a number of permits, authorizations and licenses in connection with the construction and operation of our generation facilities, electric transmission lines, natural gas transportation pipelines and gas compressor station facilities. Discharge permits, various Air Pollution Control District permits, U.S. Department of Agriculture-Forest Service permits, FERC hydroelectric generation 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. We currently have eight hydroelectric generation facilities and one transmission line project undergoing FERC license renewal.

State Energy Regulation

The CPUC

The CPUC has jurisdiction to set the rates, terms and conditions of service for our electricity distribution, natural gas distribution and natural gas transportation and storage services in California. The CPUC also has jurisdiction over our issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of our electricity and natural gas retail customers, rate of return, rates of depreciation, aspects of the siting and operation of natural gas transportation assets, oversight of nuclear decommissioning, and certain aspects of our siting and operation of our electric transmission system. Ratemaking for retail sales from our generation facilities is under the jurisdiction of the CPUC. To the extent this electricity 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.

California Legislature

Over the last several years, our operations have been significantly affected by statutes passed by the California legislature, including:

Assembly Bill 1890. AB 1890 mandated the restructuring of the California electricity industry, commencing in 1998 with the implementation of a market framework for electricity generation in which generators and other energy providers were permitted to charge market-based rates for wholesale electricity and our customers were given the choice of becoming direct access customers;

Assembly Bill 6X, or AB 6X. AB 6X, enacted in January 2001 in response to the California energy crisis, prohibited disposition of utility-owned generation facilities before January 1, 2006;

Assembly Bill 1X. AB 1X authorized the DWR beginning on February 1, 2001 to purchase electricity and sell that electricity directly to the investor owned utilities retail customers. AB 1X required the California investor-owned utilities, including us, to deliver that electricity and act as the DWR s billing and collection agent; and

Senate Bill 1976. SB 1976, enacted in September 2002, required the CPUC to allocate electricity from electricity contracts which the DWR entered into under AB 1X among the customers of the California investor-owned utilities, required us to file short and long-term procurement plans with the CPUC, contemplated that the California investor-owned utilities would resume buying electricity pursuant to these plans by January 1, 2003, and mandated new electricity procurement balancing accounts to allow recovery by the investor-owned utilities of differences between recorded revenues and costs incurred under approved procurement plans.

The California Energy Resources Conservation and Development Commission

The California Energy Resources Conservation and Development Commission, commonly called the California Energy Commission, or CEC, is the state s lead energy policy agency. It is directed, by recent legislation, to develop, in coordination with other state agencies, the state s electricity, natural gas, and transportation energy policies every two years. The CEC also is responsible for the siting of all thermal power plants over 49 MW, and it administers public interest research and development funds, as well as renewable resource programs, including the renewable energy portfolio standard program pursuant to SB 1078. See Ratemaking Mechanisms Electricity Ratemaking Electricity Procurement Renewable Energy Requirements below.

Other Regulation, Licenses and Permits

We have over 520 franchise agreements with various cities and counties that allow us to install, operate and maintain our electric, natural gas, oil and water facilities in the public streets and roads. In exchange for the right to use public streets and roads, we pay annual fees to the cities and counties under the franchises. Franchise fees are computed pursuant to statute under either the Broughton Act or the Franchise Act of 1937. However, there are 38 charter cities that can set a fee of their own determination. We also periodically obtain permits, authorizations and licenses in connection with distribution of electricity and natural gas. Under these permits, licenses and franchises, we have rights to occupy and/or use public property for the operation of our business and to conduct certain related operations.

Ratemaking Mechanisms

In setting the retail rates for our electricity and natural gas utility services, revenue requirements must first be determined. The components of revenue requirements for electricity and natural gas utility service include depreciation, operating, administrative and general expenses, taxes and return on investment, as applicable, for each area of our services, including distribution, transmission/transportation, generation/procurement and public purpose programs. Revenue requirements are designed to allow a utility an opportunity to recover its reasonable costs of providing adequate utility service, including a return of, and a fair rate of return on, its investment in utility facilities, or rate base. Revenue requirements are then allocated among customer classes (mainly residential, commercial, industrial and agricultural) and specific rates designed to produce the required revenue are set. After our rate case filings, intervenors have the opportunity to comment on our submission. The issues raised by these comments are then decided by the appropriate regulatory agency. If we and the intervenors can settle these issues, these settlements are submitted to the regulatory agency for approval.

Our primary revenue requirement proceeding is the general rate case filed with the CPUC. In the general rate case, the CPUC authorizes us to collect from ratepayers an amount known as base revenues to recover basic business and operational costs for our electricity and natural gas operations. Base revenue requirement amounts include revenue requirements related to our electricity and natural gas distribution and electricity generation operations. The general rate case typically sets annual revenue requirement levels for a three-year rate period. The CPUC authorizes these revenue requirements in general rate case proceedings based on a forecast of costs for the first, or test, year. After authorizing the revenue requirement, the CPUC allocates revenue requirements among customer classes and establishes specific rate levels. Typical intervenors in our general rate cases before the CPUC include the ORA, an independent advocacy division established to represent public utility customers in CPUC proceedings, and TURN.

We have recently entered into two settlement agreements with various intervenors in our 2003 general rate case, both of which have been submitted to the CPUC for approval. In July 2003, we reached the electricity generation settlement with various intervenors that would set a 2003 generation operations revenue requirement. In September 2003, we reached the rate case settlement on all disputed economic issues related to the electricity and natural gas distribution revenue requirement raised in the 2003 general rate case, with the exception of our request that the CPUC include the costs of a pension contribution in our revenue requirement. The CPUC will resolve the pension contribution issue, as well as other issues raised by non-settling intervenors, in its final decision and our revenue requirement will be adjusted accordingly. Under the CPUC settlement agreement, the CPUC agreed to act promptly on the 2003 general rate case. We have agreed in the proposed rate case settlement that our next general rate case would determine revenues for 2007.

We may receive annual increases in the base revenues established during the test year of a general rate case, known as attrition rate adjustments, for the years between general rate cases to avoid a reduction in earnings in those years due to, among other things, inflation and increases in invested capital. Under the generation settlement and rate case settlement, attrition revenue increases for 2004, 2005, and 2006 would be authorized in the 2003 general rate case. The attrition increase for 2004 and 2005 would be calculated as the prior year s revenue requirement multiplied by the change in the consumer price index. For 2006, the 2005 revenue requirement would be multiplied by the sum of the change in the consumer price index plus 1% to calculate the attrition increase. The generation attrition revenue requirement would also include additional revenues to cover the costs of refueling activities at our Diablo Canyon power plant. For electricity and natural gas distribution operations, the attrition increases would be subject to a minimum increase of 2% and a maximum increase of 3% for 2004, a minimum increase of 2.25% and a maximum increase of 3.25% for 2005, and a minimum increase of 3% and a maximum increase of 4% for 2006. For electricity generation operations, the attrition increases would be subject to a minimum increase of 1.5% and a maximum increase of 3% for 2004 and 2005, and a minimum increase of 2.5% and a maximum increase of 4% for 2006. The rate case settlement notes that outcomes in future cost of capital proceedings could affect our revenue requirement, including the attrition adjustments.

Another major CPUC proceeding for determining revenue requirements is the annual cost of capital proceeding. Each year, the CPUC determines the rate of return that we may earn and recover from ratepayers on our electricity and natural gas distribution assets and generation assets. For our electricity and natural gas distribution operations and electricity generation operations, our currently authorized return on equity is 11.22% and our currently authorized cost of debt is 7.57%. We also have a currently authorized capital structure of 48.00% common equity, 46.20% long-term debt and 5.80% preferred equity. The November 2002 decision in our 2003 cost of capital proceeding adopted these authorized figures, but held the case open to address the effect that implementing and financing a confirmed plan of reorganization would have on our return on equity, costs of debt and preferred equity and ratemaking capital structure. Subsequently, in February 2003, we filed a petition to modify the November 2002 decision and waive the normal requirement that we file a test year 2004 cost of capital application. In May 2003, the CPUC granted our request, exempting us from filing a test year 2004 cost of capital application.

Under the CPUC settlement agreement, the CPUC will set our capital structure and authorized return on equity in our annual cost of capital proceedings in its usual manner. However, from January 1, 2004 until Moody s has issued an issuer rating for us of not less than A3 or Standard & Poor s has issued a long-term issuer credit rating for us of not less than A-, our authorized return on equity will be no less than 11.22% per year and our authorized equity ratio for ratemaking purposes will be no less than 52%, except that, for 2004 and 2005, our authorized equity ratio will equal the greater of the proportion of equity in the forecast of our average capital structure for calendar years 2004 and 2005 filed in our cost of capital proceedings and 48.6%.

The FERC determines our revenue requirements for our wholesale and retail electric transmission operations, including the return on our electric transmission-related assets. The return on our natural gas transportation and storage business has been incorporated in rates that have been established and modified in a series of agreements with the CPUC.

Electricity Ratemaking

Overview

In 1998, California implemented AB 1890, which mandated the restructuring of the California electricity industry and established a market framework for electricity generation in which generators and other electricity providers were permitted to charge market-based prices for wholesale electricity. As required by AB 1890, beginning January 1, 1997 electricity 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%. The frozen rates were designed to allow us to recover our authorized utility costs and, to the extent the frozen rates generated revenues in excess of our authorized utility costs, to recover our transition costs. During the California energy crisis, these frozen rates were not sufficient to cover our electricity procurement and other costs. In the first quarter of 2001, the CPUC authorized us to begin collecting a one and a three cent per kWh electricity surcharge. In May 2001, the CPUC authorized us to collect an additional half-cent per kWh electricity surcharge.

Under the CPUC settlement agreement, the CPUC acknowledged and agreed that base and surcharge revenues accrued or collected by us through and including December 31, 2003 are property of our Chapter 11 estate, have been or will be used for utility purposes, including to pay creditors in our Chapter 11 case, have been included in our retail electricity rates consistent with state and federal law and are not subject to refund (except for headroom revenues greater than $875 million in 2003).

Electricity Distribution

2003 General Rate Case. The rate case settlement proposes that we would receive a total 2003 revenue requirement of $2.5 billion for electricity distribution operations, representing a $236 million increase in our total electricity distribution revenue requirement over the currently authorized amount. For a discussion of the proposed natural gas distribution revenue requirement, see Natural Gas Ratemaking below and for a discussion of the proposed electricity generation revenue requirement, see Electricity Generation below.

The rate case settlement provides that the amount of electricity distribution rate base on which we would be entitled to earn an authorized rate of return would be $7.7 billion, based on recorded 2002 plant and including weighted average capital additions for 2003 of $292 million. The rate case settlement also provides for a new balancing account, effective January 1, 2004, to ensure that we recover our authorized total electricity distribution revenue requirement regardless of our level of sales. In another phase of the general rate case addressing how we respond to storm outages and other reliability issues, we reached an agreement with the ORA that would allow us to recover up to a maximum of $9 million in 2003 and up to a maximum of $2.3 million in each of 2004, 2005, and 2006. We also reached an agreement with the California Coalition of Utility Employees that proposes a reliability performance incentive mechanism for us beginning in 2004. Under the proposed incentive mechanism, we would receive a maximum reward or penalty of $42 million per year for the years 2004 through 2009 depending on whether we met the improvement targets on our outage duration and frequency performance. In order to provide us the opportunity to achieve the improvement targets, the agreement provides for up to $27 million in additional revenues each year of the incentive mechanism (to be recorded in a one-way balancing account) to be spent exclusively on reliability improvement activities. Both of these agreements are pending CPUC approval.

We cannot predict when or whether the rate case settlement will be approved by the CPUC, or if approved, the outcome of any rehearing petitions or appeals that may be filed.

Electricity Generation

In April 2002, the CPUC issued a decision authorizing us to recover reasonable costs incurred in 2002 for our own electricity generation operations, subject to reasonableness review in our 2003 general rate case and other proceedings. In May 2003, the CPUC issued a resolution approving our proposed tariff revisions and our request to establish various balancing and memorandum accounts with modifications in compliance with its April 2002 decision.

In July 2003, we filed a motion with the CPUC for approval of the generation settlement that would set a total 2003 generation revenue requirement of $955 million. This revenue requirement excludes fuel expense, the cost of electricity purchases, the DWR revenue requirement and the nuclear decommissioning revenue requirement. If approved by the CPUC, the generation settlement would resolve all generation-specific issues raised in our 2003 general rate case, but would not resolve various tax methodology issues or the amount of administrative and general expenses and common plant to allocate to generation.

The rate case settlement discussed above would resolve these remaining issues. If the generation settlement and the rate case settlement are approved by the CPUC, our revenue requirement for our electricity generation operations would be set at $912 million for 2003, representing a $38 million increase over the currently authorized amount. In addition, the rate case settlement provides for a new balancing account, effective January 1, 2004, to ensure that we recover our authorized electricity generation revenue requirements regardless of the level of sales.

Under the CPUC settlement agreement, our adopted 2003 electricity generation rate base of $1.6 billion was deemed just and reasonable by the CPUC and not subject to modification, adjustment or reduction, except as necessary to reflect capital expenditures and changes in authorized depreciation. This reaffirmation of our electricity generation rate base allows recognition of an after-tax regulatory asset of approximately $800 million (which is equivalent to approximately $1.3 billion pre-tax).

Advanced Metering Improvements

The CPUC may require the California investor-owned utilities to implement an advanced metering infrastructure to enable them to measure residential and small commercial customers usage of electricity on a time-of-use basis, and to apply varying tariffs, or demand responsible tariffs, during peak and non-peak demand periods with the goal of encouraging customers to reduce energy consumption during peak demand periods. Advanced meters are capable of recording usage in time intervals and can be read remotely. While demand responsive tariffs are being implemented for large industrial customers that have advanced metering systems in place, a statewide pilot program is in progress to test whether and how much residential and small customers will respond to dynamic, or time varying, rates. If the CPUC determines that it would be cost-effective to install advanced metering on a large scale and orders us to proceed with large scale development of advanced metering for residential and small commercial customers, we expect that we would incur substantial costs to convert our meters, build the meter reading network and build the data storage and processing facilities to bill a substantial portion of our customers based on dynamic rates.

Nuclear Decommissioning Cost Triennial Proceeding Application

In October 2003, the CPUC adopted 2003 revenue requirements of $18.4 million for decommissioning Humboldt Bay Unit 3 and $8.3 million for a custodial mode of decommissioning, or SAFSTOR, operating and maintenance costs. The CPUC did not provide for an additional revenue requirement for decommissioning our Diablo Canyon power plant, finding that the trust funds for our Diablo Canyon power plant are sufficient to pay for its eventual decommissioning. The $26.7 million revenue requirement adopted by the CPUC resulted in a $4.5 million decrease from the previously adopted revenue requirement.

Electricity Procurement

AB 1X and SB 1976. As a consequence of the California energy crisis, on January 17, 2001, the Governor of California signed an order declaring an emergency and authorizing the DWR to purchase electricity to maintain the continuity of supply to retail customers. This was followed by AB 1X which authorized the DWR to purchase electricity and sell that electricity directly to the California investor-owned utilities retail end-use customers. AB 1X also required us to deliver the electricity purchased by the DWR over our distribution systems and to act as a billing and collection agent for the DWR, without taking title to DWR purchased electricity or reselling it to our customers.

AB 1X allows the DWR to recover, as a revenue requirement, among other things, costs of electricity and associated transmission and related services, principal and interest on bonds issued to finance the purchase of electricity, administrative costs, and certain other amounts associated with purchasing electricity. AB 1X authorizes the CPUC to set rates to cover the DWR s revenue requirements, but prohibits the CPUC from increasing electricity rates for residential customers who use less electricity than 130% of their existing baseline quantities.

Under AB 1X, the DWR was prohibited after December 31, 2002 from entering into new electricity purchase contracts and from purchasing electricity on the spot market. SB 1976, which became law in September 2002, required the CPUC to allocate electricity from existing DWR contracts among the customers of the California investor-owned utilities, including our customers. SB 1976 also required us to file short-term and long-term procurement plans for approval with the CPUC. On September 19, 2002, the CPUC issued a decision allocating electricity from the DWR contracts to the customers of the three California investor-owned utilities. The DWR continues to be legally and financially responsible for these contracts.

Procurement Resumption and the ERRA. In October 2002, the CPUC issued a decision ordering us to resume full procurement of electricity for our residual net open position on January 1, 2003 and to file short and long-term procurement plans. On January 1, 2003, we, along with the other California investor-owned utilities became responsible for scheduling and dispatch of the electricity subject to the DWR allocated contracts on a least-cost basis and for many administrative functions associated with those contracts. The California investor-owned utilities also resumed the function of procuring electricity to meet their respective residual net open positions. On December 19, 2002, the CPUC adopted a 2003 short-term procurement plan for us. The CPUC also authorized us to extend our planning into the first quarter of 2004 and directed us to hedge all our 2004 first quarter residual net open position with transactions entered into in 2003.

We filed our long-term procurement plan, covering the next 20 years, on April 15, 2003. We filed our short-term procurement plan covering 2004 on May 15, 2003. We expect that the CPUC will issue a final decision on our long-term procurement plan and our 2004 short-term procurement plan in December 2003.

In August 2003, the CPUC approved our proposal to begin procuring up to one-half of our residual net open position for 2004 before the CPUC s formal adoption of our 2004 procurement plan. We conducted a competitive solicitation and submitted our selection criteria to the CPUC for approval.

Under AB 1X, the CPUC has no authority to review the reasonableness of procurement costs in the DWR s contracts, although our administration of the DWR allocated contracts and our least-cost dispatch of the electricity associated with the DWR allocated contracts may be subject to CPUC review. Under decisions entered in December 2002 and June 2003, the CPUC established a maximum annual procurement disallowance for administration of contracts and least-cost dispatch, including the DWR allocated contracts, equal to $36 million. Activities excluded from the disallowance cap include gas procurement activities in support of our new contracts, electricity generation resources, qualifying facilities contracts, and certain electricity generation expenses. This maximum disallowance amount is subject to audit for our adopted annual administrative costs of managing procurement activities in the 2003 general rate case. We can provide no assurance that the CPUC will not increase or eliminate this maximum annual procurement disallowance in the future.

A central feature of the SB 1976 regulatory framework is its direction to the CPUC to create new electricity 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 California investor-owned utility s electricity procurement plan at least semi-annually and adjust rates or order refunds, as appropriate, to properly amortize the balancing accounts. The CPUC must establish the schedule for amortizing the over-collections or under-collections in the electricity procurement balancing accounts so that the aggregate over-collections or under-collections reflected in the accounts do not exceed 5% of the California investor-owned utility 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. Thereafter, the CPUC is required to conduct electricity 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.

Effective January 1, 2003, we established the ERRA to record and recover electricity costs associated with our authorized procurement plan, excluding the costs associated with the DWR allocated contracts. In February 2003, we filed our 2003 ERRA forecast application requesting that the CPUC reset our 2003 ERRA revenue requirement to $1.4 billion. We are authorized to file an application to change retail electricity rates when we reach the trigger threshold (*i.e.*, when our forecasts indicate we will face an under-collection of electricity procurement costs in excess of 5% of our prior year s generation revenues, excluding amounts collected for the DWR). In our February 2003 application, we requested the CPUC to set the trigger threshold at $224 million. The CPUC will finalize our starting ERRA revenue requirement and ERRA trigger threshold after it reviews our ERRA application. We cannot predict when or whether we will reach the trigger threshold. On August 15, 2003, we and the ORA proposed a stipulation to an administrative law judge and the CPUC that would reduce our 2003 ERRA revenue requirement by $40 million, to $1.37 billion. The CPUC issued a decision adopting the stipulation in October 2003.

In August 2003, we filed an application requesting that the CPUC approve the 2004 ERRA forecast revenue requirement of $1.5 billion associated with our 2004 short-term procurement plan and approve as reasonable our ERRA recorded costs for the period from January 2003 through May 2003. The CPUC s review of our procurement activities will examine our least-cost dispatch of the resource portfolio, fuel expenses for our electricity generation, contract administration, including administration of the DWR allocated contracts, our existing qualifying facility contracts and other power purchase agreements, renewable energy contracts, and our decision to engage in market transactions in the context of our overall prudent contract administration and least-cost dispatch of generation resources. We have also asked the CPUC to approve our proposed revenue requirement of $840 million to recover the 2004 costs related to the above-market generation and procurement costs and certain other generation-related costs.

DWR Electricity Revenue Requirement, Operating Agreement and Bond Charge. Although AB 1X prohibited the DWR from purchasing electricity on the spot market and from entering into new agreements to purchase electricity after December 31, 2002, the DWR is currently legally and financially responsible for the long-term contracts it entered into before December 31, 2002. The DWR pays for its costs of purchasing electricity from a revenue requirement collected from electricity customers of the three California investor-owned utilities through a charge, called a power charge. Because we act as a billing and collection agent for the DWR, amounts collected on behalf of the DWR (related to its revenue requirement) are not included in our revenues.

In December 2002, the CPUC issued a decision allocating approximately $2.0 billion of the DWR s 2003 $4.5 billion total statewide power charge-related revenue requirement to our customers. This revenue requirement includes the forecasted costs associated with the DWR allocated contracts during 2003. A December 2002 operating order required us to perform the operational, dispatch and administrative functions for the DWR allocated contracts beginning on January 1, 2003 on a least-cost basis. In April 2003, we and the DWR entered into a CPUC-approved operating agreement that supersedes the December 2002 operating order.

In July 2003, the DWR submitted a supplemental 2003 revenue requirement to the CPUC that reduced the amount of the total 2003 statewide power charge-related revenue the DWR was requesting by approximately $1.0 billion. On September 4, 2003, the CPUC issued a decision that allocated this $1.0 billion reduction among the customers of the three California investor-owned utilities. The decision allocated approximately $444 million of the reduction to our retail electricity customers and required us to provide a one-time bill credit to our customers to pass through the revenue requirement reduction within 45 days. Prior ambiguities in the formula that determines the calculation of our collections payable to the DWR resulted in our underpayment of amounts we paid the DWR through June 2003. These ambiguities were resolved by the CPUC in a decision issued on September 4, 2003. At June 30, 2003, we had accrued a $516 million reserve based on our own estimate of underpayments. We subsequently paid the DWR $77 million (which equals the $521 million shortfall ultimately determined to be due to the DWR, less our customers approximately $444 million share of the $1.0 billion statewide reduction in the DWR s 2003 revenue requirement). This approximately $444 million share of the statewide revenue reduction has been returned to our customers in the form of bill credits issued to our customers in September and October 2003. The September 4, 2003 decision also reduces our DWR power charge remittance rate from $0.105 per kWh to $0.095 per kWh effective September 2003. This reduction in the remittance rate is in addition to the approximately $444 million reduction described above.

Our customers also must pay a share of the costs associated with the DWR s $11.3 billion bond offering completed in November 2002. The proceeds of this bond offering were used to repay the State of California and lenders to the DWR for electricity purchases made before the DWR electricity revenue requirement was in place and to provide the DWR with funds needed to make its electricity purchases. The debt service costs are collected from our electricity customers as part of the DWR revenue requirement. We collected and passed through to the DWR from our rates approximately $172 million in bond charges during the six months ended June 30, 2003. We expect to collect and pass through DWR bond charges of approximately $352 million during 2003. In its proposed revenue requirement for 2004, the DWR states that it expects to collect $873 million for bond charges in 2004 that would be collected from the customers of the California investor-owned utilities. The CPUC is responsible for allocating the proposed 2004 bond charge-related revenue requirement among the customers of the California investor-owned utilities. Under the CPUC settlement agreement, the CPUC has agreed that DWR bond charges allocated to our customers will be included in our rates in a manner that will not affect our collection of other authorized costs or return on capital.

The DWR filed its proposed 2004 revenue requirement with the CPUC on September 19, 2003. The DWR has proposed a $4.5 billion revenue requirement for power charge-related costs and $873 million in bond charge-related costs in 2004 that would be collected from the customers of the California investor-owned utilities. The CPUC is responsible for allocating the proposed 2004 revenue requirement among the customers of the California investor-owned utilities.

The CPUC s allocation of the DWR revenue requirement for the 2001-2002 period among the three California investor-owned utilities is (and the DWR revenue requirements for 2003 and 2004 may be) subject to adjustments based on the actual amount of electricity purchased by the DWR for the utilities customers during the 2001-2002 period. The CPUC allocated approximately 48.3% of the adopted DWR power charge-related revenue requirement for the 2001-2002 period, or about $4.4 billion, to us.

In testimony we submitted to the CPUC in October 2003, we estimated that we over-remitted $107 million in power charges to the DWR for the 2001-2002 period based on the allocation methodology applied by the CPUC in determining the allocation of the 2001-2002 DWR power charge-related revenue requirement. We also proposed that the CPUC use a different allocation methodology under which we estimate we over-remitted $211 million. Testimony submitted by Southern California Edison and other parties includes varying estimates of our adjustment depending on the allocation method proposed. Southern California Edison calculated that we over-remitted approximately $101 million in power charges to the DWR based on the allocation methodology applied by the CPUC in determining the allocation of the DWR power charge-related revenue requirement. However, Southern California Edison also has proposed that the CPUC apply the allocation methodology used to allocate the DWR bond charge-related revenue requirement to allocate the bond proceeds among the customers of the California investor-owned utilities and, under this methodology, has estimated that we have under-remitted $453 million in DWR revenue requirements. Our testimony noted that the CPUC had already rejected this proposal in its decision allocating the 2003 DWR bond charge-related revenue requirement.

We have proposed to include any adjustments to the 2001-2002 DWR revenue requirement in each California investor-owned utility s allocation of the 2004 DWR revenue requirement to be collected through the DWR remittance rate. Southern California Edison supports this proposal, but San Diego Gas & Electric Company has proposed that any under-remittance be paid by the California investor-owned utility immediately. CPUC hearings are scheduled to begin on October 27, 2003 and the CPUC is expected to issue a decision on the 2001-2002 adjustments (as well as the 2004 DWR revenue requirement) in January 2004.

We expect that any amounts the CPUC determines that we have under-remitted or over-remitted to the DWR for the 2001-2002 period will be included in the DWR revenue requirements in 2004 and subsequent periods, and collected or refunded on a going forward basis from our customers. However, we are unable to predict the outcome of this matter. If the CPUC retroactively determines that we have under-remitted a material amount to the DWR and orders us to make a one-time payment from cash on hand rather than collect the under-remitted amount from customers on a going forward basis, our financial condition and results of operations would be materially adversely affected.

On October 2, 2003, in connection with our prior lawsuit against the DWR, a California court of appeal issued a decision finding that the DWR is required by law to conduct a review to determine whether its revenue requirements are just and reasonable, but also finding that the California Administrative Procedure Act did not require the DWR to hold public hearings as part of its determination. If some of the DWR s costs are ultimately determined not to have been reasonably incurred and therefore disallowed from recovery from our customers, then the DWR s charges for these costs to ratepayers may be reduced within our service territory.

The DWR has stated publicly that it intends to transfer full legal title to, and responsibility for, the DWR allocated contracts to the California investor-owned utilities as soon as possible. However, the DWR allocated contracts cannot be transferred to us without the consent of the CPUC. The CPUC settlement agreement provides that the CPUC will not require us to accept an assignment of, or to assume legal or financial responsibility for, the DWR allocated contracts unless each of the following conditions has been met:

- after assumption, our issuer rating by Moody s will be no less than A2 and our long-term issuer credit rating by Standard & Poor s will be no less than A;
- the CPUC first makes a finding that the DWR allocated contracts being assumed are just and reasonable; and
- the CPUC has acted to ensure that we will receive full and timely recovery in our retail electricity rates of all costs associated with the DWR allocated contracts without further review.

The CPUC settlement agreement does not limit the CPUC s discretion to review the prudence of our administration and dispatch of the DWR allocated contracts consistent with applicable law.

Qualifying Facilities and Other Existing Bilateral Agreements. Based on a CPUC decision dated April 4, 2002 that established our revenue requirements for our electricity generation operations, the costs of our existing contracts with qualifying facilities and other electricity providers are passed through to ratepayers in full. For 2002, a forecast of approximately $1.8 billion for these costs was adopted. Since the beginning of 2003, we have been recovering the actual costs of qualifying facilities and other power purchase agreements through ratemaking mechanisms, including the ERRA. See Procurement Resumption and the ERRA above.

Direct Access. AB 1890 also gave customers the choice of continuing to buy electricity from the investor-owned utilities or, beginning in April 1998, becoming direct access customers. Most of our customers continued to buy electricity from us. Pursuant to AB 1X, the CPUC suspended the right of retail end-user customers to become direct access customers on September 20, 2001. This prevented additional customers from entering into contracts to purchase electricity from alternate energy service providers after that date. In a subsequent decision issued on March 21, 2002, the CPUC permitted all customers who had entered into direct access contracts on or before September 20, 2001 to remain direct access customers. To avoid a shift of costs from direct access customers to customers who receive bundled service, the CPUC in a November 2002 decision established the CRS mechanism to implement utility-specific non-bypassable charges on direct access customers for their shares of the bond costs and electricity costs incurred by the DWR and the above-market cost related to our own generation resources and electricity purchase contracts. The November 2002 decision imposed a cap on the CRS of $0.027 per kWh. We implemented this capped surcharge on January 1, 2003. On July 10, 2003, the CPUC determined that the CRS cap of $0.027 per kWh should remain in effect, subject to further prospective adjustment in the annual DWR revenue requirement proceedings. A July 2003 decision, recognizing that not all the non-bypassable charges composing the CRS fit under the cap, ordered that the CRS funds be applied to recover (in the following order) the DWR bond charges, our ongoing above-market costs relating to our own generation resources and electricity purchase contracts and the DWR power charges. The July 2003 decision found that, subject to prospective adjustment in the annual DWR revenue requirement proceeding, the CRS cap of $0.027 per kWh, plus interest on the direct access CRS under-collection, will be sufficient to repay any shortfall to customers who receive bundled service by the time the DWR allocated contracts terminate. The CPUC also held in April and July 2003 decisions that certain customers reducing or terminating electricity service with us after February 2001 also pay the CRS, subject to specific exemptions.

To the extent the CRS cap results in an under-collection of DWR charges, we would have to remit the shortfall to the DWR from bundled customers funds. Since DWR pass-through revenues are determined based upon a fixed revenue requirement, to the extent that we remit additional CRS amounts to the DWR, those remittances reduce the amount of revenues we must pass through for bundled customers. We expect to collect approximately $110 million per year more in 2003 than in 2002 from direct access customers due to the CRS.

Community Choice Aggregators. In October 2003, the CPUC instituted a rulemaking implementing AB 117, which permits California cities and counties to purchase and sell electricity for their residents once they have registered as community choice aggregators. Under AB 117, we would continue to provide distribution, metering and billing services to the community choice aggregators customers and be those customers provider of electricity of last resort. However, once registration has occurred, each community choice aggregator would procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from us. To prevent a shifting of costs to customers of a utility who receive bundled services, AB 117 requires the CPUC to determine a cost-recovery mechanism so that retail end-users of the community choice aggregator would pay an appropriate share of DWR costs and certain of that utility s costs that are fixed and unavoidable.

Renewable Energy Requirements. On August 22, 2002, the CPUC issued a decision requiring the California investor-owned utilities to contract for electricity from renewable resources for delivery in 2003 by an additional 1%. The decision required that these interim renewable resources contracts range from five to 15-year terms. In addition, the CPUC decision determined that any renewable energy contract which includes electricity prices equal to or less than a provisional benchmark of $0.0537 per kWh will be deemed reasonable. Prices above the benchmark may also be pre-approved for cost recovery through the pre-approval process adopted in the decision.

In June 2003, the CPUC issued a decision pursuant to SB 1078 that adopts the framework for a renewable energy portfolio standard requiring each California investor-owned utility to increase purchases of renewable energy by at least 1% of its retail sales per year. By the end of 2017, we must purchase at least 20% of our total electricity from renewable resources. Under SB 1078, we were not obligated to purchase additional renewable energy until we received an investment grade credit rating. However, under subsequently enacted SB 67, we may be required to purchase additional renewable energy once we are able to do so on reasonable terms and the renewable energy contracts will not impair the restoration of our creditworthiness. Until that time, we will accumulate an APT based on 1% of annual retail sales. When we receive an investment grade credit rating or the CPUC determines that the SB 67 requirements are satisfied, we expect to enter into purchase contracts for renewable energy to meet our accumulated APT. Although we cannot predict the terms, including price, of those contracts, the CPUC s decision requires that the purchase price under those contracts to be at or below a market price benchmark established by the CPUC after the bids have been received. If we exceed our APT, we can apply the excess to meet the APT in future years. For under-procurement, the decision allows us to carry over an annual deficit of 25% of the current year s APT to the next three years without explanation. Failure to meet minimum APTs without prior CPUC approval would result in an automatic penalty of $0.05 per kWh, subject to an annual penalty cap of $25 million.

We currently estimate the annual 1% increase in renewable resource electricity in our portfolio will initially require between 80 and 100 MW of additional renewable capacity to be added per year. The CPUC approved offers we submitted that were sufficient to meet our 2003 renewable energy requirement in December 2002. Pursuant to this approval, we have entered into three contracts with renewable energy suppliers that include both capacity and energy payments. During 2003, electricity under the contracts is sold by the suppliers to the DWR, which resells the electricity to our customers. We expect to reimburse the DWR for the contract costs. After 2003 and once certain conditions are met, we will become obligated under the contracts for the remainder of their five-year terms. We have submitted to the CPUC for approval several contracts intended to meet our 2004 renewable energy requirement.

In September 2003, we submitted to the CPUC for approval several renewable contracts pursuant to an assigned commissioner ruling in August 2003 that permitted bilateral negotiations with renewable suppliers prior to the implementation of renewable energy portfolio standard requirements. The CPUC approved the contracts in October 2003.

Electric Transmission

Our electric transmission revenues and our wholesale and retail transmission rates are subject to authorization by the FERC. We have two sources of transmission revenues, charges under our transmission owner tariff and charges under specific contracts with existing wholesale transmission customers that pre-date our participation in the ISO. Customers that receive transmission services under these pre-existing contracts, referred to as existing transmission contract customers, are charged individualized rates based on the terms of their contracts. Transmission rates established by FERC are included by the CPUC in our retail electricity rates and collected from retail electricity customers receiving bundled service under the federal filed rate doctrine.

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. All these changes require FERC approval. The FERC approved those changes now in effect before their implementation.

Transmission Owner Rate Cases. Under the FERC s regulatory regime, we are able to file a new base transmission rate case under our transmission owner tariff whenever we deem it necessary to increase our rates within certain guidelines set forth by the FERC. We are typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process.

Our transmission owner tariff includes two rate components:

- base transmission rates, which are intended to recover our operating and maintenance expenses, depreciation and amortization expenses, interest expense, tax expense and return on equity; and

- the rates we charge our transmission owner tariff customers to recover ISO charges for both reliability service costs and an ISO transition charge associated with a ten-year shift from utility-specific transmission charges to an ISO grid-wide charge.

We derive the majority of our transmission revenue from base transmission rates. The transmission rates charged to transmission owner 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 us as a transmission owner.

On January 13, 2003, we filed an application with the FERC requesting authority to recover $545 million in electric transmission retail rates annually, a 44% increase over the revenue requirement then in effect. The requested increase is mainly attributable to significant capital additions and replacements made to our electric transmission system to accommodate load growth, maintain the infrastructure and 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%. The January 13 proposed rates went into effect, subject to refund, on August 13, 2003.

Existing Wholesale Transmission Contracts. On March 28, 2003 we filed an application requesting an update to the rates contained in several of our existing wholesale transmission contracts. The FERC issued an order on May 27, 2003 that will allow the proposed rates for then existing transmission contract customers to go into effect, subject to refund, on October 28, 2003. Our proposed rates to these existing transmission contract customers are designed to recover $17 million in additional revenues on an annual basis.

Our existing transmission contract 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. Our existing municipal utility transmission contract customers distribute electricity to municipal facilities and, in many cases, to the homes and businesses of retail electricity customers located inside their municipalities.

Transmission Control Agreement. On March 30, 1998, as a result of AB 1890 we entered into a TCA with the ISO, Southern California Edison Company and San Diego Gas and Electric Company. As a transmission owner, we are required to give two years notice if we wish to withdraw from the TCA. Under the TCA, the transmission owners assign operational control of their electric transmission systems to the ISO. In addition, as parties to the TCA, the transmission owners are responsible under the ISO tariff for the costs of the reliability must run agreements between the ISO and owners of the reliability must run plants. Under the reliability must run agreements, reliability must run plants must remain available to generate electricity when needed for transmission system reliability upon the ISO s demand. At June 30, 2003, the ISO had reliability must run agreements for which we could be obligated to pay an estimated $911 million in net costs during the period July 1, 2003 to June 30, 2005. The amount will be reduced by amounts we expect to receive under the reliability must run contracts related to our generation facilities. These costs are recoverable under applicable ratemaking mechanisms.

Reliability Services Costs. The ISO bills us for reliability services based on payments that the ISO makes to generators under reliability must run agreements and for locational out-of-market calls required to support reliability of our transmission system. The costs of reliability must run agreements attributed to supporting our historic transmission control area are charged to us as a participating transmission owner. These costs were approximately $311 million in 2002. Under our transmission owner tariff, we charge our customers rates designed to recover these reliability service charges, without mark-up or service fees. We record these customer charges as operating revenue and record a corresponding expense since we must remit this revenue to the ISO. We track costs and revenues related to reliability services in the reliability services balancing account. In general, for each of these types of costs, we will use the difference between actual ISO charges and the revenues we collect and those we have forecasted to either offset or increase the specific revenue requirement for those costs when we next file an annual balancing account rate case related to the costs.

It is possible that we may receive a refund of reliability must run costs that we previously paid to the ISO. In June 2000, a FERC administrative law judge issued an initial decision approving rates that, if affirmed by the FERC, would require the subsidiaries of Mirant that are parties to three reliability must run agreements with the ISO to refund to the ISO, and the ISO to refund to us, excess payments of approximately $300 million, including interest, for availability of Mirant s generation facilities under these agreements. However, on July 14, 2003, Mirant filed a petition for reorganization under Chapter 11. We are unable to predict at this time when the FERC will issue a final decision on this issue, what the FERC s decision will be, and the amount of any refunds, which may be impacted by Mirant s Chapter 11 filing, we will ultimately receive. Any refunds received would be used to lower future reliability services rates depending on the time period covered by the refunds. If the resolution involves other than a cash refund, it is uncertain how the resolution would be reflected in rates.

Transmission Access Charge. In March 2000, the ISO filed an application with the FERC seeking to establish its own transmission access charge as directed by AB 1890. The ISO s transmission access charge methodology provides for transition to a uniform statewide high-voltage transmission rate, based on the revenue requirements of all participating transmission owners associated with facilities operated at 200 kV and above. The transmission access charge methodology also requires us and other transmission owners, during a ten-year transition period, to pay a charge based on certain costs incurred by new participating transmission owners. These costs result from the cost differential of the relatively high-cost systems of the new ISO participants being included in the ISO controlled transmission grid. Our obligation for this cost differential is proposed to be capped at $32 million per year during the ten-year transition period. The cost associated with transmission access charges that are higher than utility-specific access charges are recovered in a separate component of the transmission owner tariff.

Scheduling Coordination. We serve as the scheduling coordinator with the ISO for transmission service on the ISO-controlled grid for some of our existing transmission contract customers. The ISO bills us for providing services associated with these customers loads and resources. In March 2003, we requested that the FERC permit us to recover $83.1 million in scheduling coordination costs from our existing transmission contract customers for the period from April 1, 1998 to August 31, 2002. Some of our existing transmission contract customers have challenged our request to recover the scheduling coordinator costs. Due to these challenges, we are uncertain whether we will be able to fully recover these costs.

Natural Gas Ratemaking

Natural Gas Distribution

2003 General Rate Case. The rate case settlement would result in total 2003 revenue requirement of $927 million for our natural gas distribution operations, representing a $52 million increase in our total natural gas distribution revenue requirement over the currently authorized amount.

The rate case settlement provides that the amount of natural gas distribution rate base on which we would be entitled to earn an authorized rate of return would be approximately $2.1 billion, based on recorded 2002 plant, and including weighted average capital additions for 2003 of $89.2 million.

Our natural gas distribution costs and related balancing account balances are allocated to customers in the biennial cost allocation proceeding. In the interim year the proceeding is updated for purposes of amortizing any accumulation in the balancing accounts. Balancing accounts for natural gas distribution and public purpose program revenue requirements accumulate differences between authorized revenue requirements and actual base revenues. We currently anticipate submitting our next biennial cost allocation proceeding application in the spring of 2004 with rates to be effective at the beginning of 2005.

Natural Gas Transportation and Storage

In 1998, we implemented the Gas Accord under which the natural gas transportation and storage services we provide were separated for ratemaking purposes from our distribution services. The Gas Accord changed the terms of service and rate structure for natural gas transportation, allowed our core customers to purchase natural gas from competing suppliers, and established natural gas transportation rates through 2002 and natural gas storage rates through March 2003. In addition, the Gas Accord established an incentive mechanism whereby we recover our core procurement costs. Under the Gas Accord, we are at risk of not recovering our natural gas transportation and storage costs and do not have regulatory balancing account protection for over-collections or under-collections of natural gas transportation revenues.

In August 2002, the CPUC approved the Gas Accord settlement that provided for a one-year extension of our existing natural gas transportation rates and terms and conditions of service, as well as rules governing contract extensions and a contract solicitation period for new contracts. In January 2003, we filed an amended Gas Accord II application with the CPUC proposing to permanently retain the Gas Accord market structure, extend the incentive mechanism for recovery of core procurement costs, and increase our rates for natural gas transportation service for 2004 and for storage service for the period from April 1, 2004 to March 31, 2005 by $30 million after removal of the cost of capital issues from this proceeding.

The amended Gas Accord II application proposes a rate increase for 2004 calculated on a demand or throughput forecast basis. In addition, for the 12-month period ending December 31, 2004 for transportation service, and for the 12-month period ending March 31, 2005 for storage service, we propose to provide an option for current holders of contract capacity to extend their rights and a structured contract solicitation period be held for any capacity not currently under contract. We may experience a material reduction in natural gas transportation operating revenues if we are unable to renew or replace existing transportation contracts at the beginning or throughout the Gas Accord II period, if we are forced to renew or replace those contracts on less favorable terms than adopted by the CPUC, or if overall demand for transportation and storage services is less than anticipated and reflected by the CPUC in rates. A proposed decision in the amended Gas Accord II application proceeding is expected in the fourth quarter of 2003. Until the CPUC issues a decision, the natural gas transportation and storage rates set forth in the Gas Accord settlement will continue to be in effect. We cannot predict what the outcome of this proceeding will be, or whether the outcome will materially adversely affect our financial condition or results of operations.

Under the Gas Accord settlement, as with the Gas Accord, we are at risk for any natural gas transportation revenue volatility. Capacity is sold at competitive market-based rates within a cost-of-service tariff framework. At the end of 2002, we filed a report with the CPUC that included the end of period amounts in our natural gas balancing accounts. This filing increased our core and noncore transportation rates and revenue requirements by $103 million effective January 1, 2003.

Natural Gas Procurement

We set the natural gas procurement rate for core customers monthly based on the forecasted costs of natural gas, core pipeline capacity and storage costs. We reflect the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rates.

The Gas Accord also established the CPIM, which is used to determine the reasonableness of our costs of purchasing natural gas for our customers. The Gas Accord settlement agreement extended the CPIM for one year through December 2003. Under the CPIM, our purchase costs are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where we typically purchase natural gas. Costs that fall within a tolerance band, which is currently 99% to 102% around the benchmark, are considered reasonable and fully recoverable in customers rates. Currently, one-half of the costs outside the tolerance band are recoverable in our customers rates, and our customers receive the benefits of one-half of any savings outside the tolerance band in their rates. However, in June 2003, we reached a settlement with the ORA that, if approved by the CPUC, would increase the amount of savings passed through to ratepayers from one-half to three-fourths, retroactive to November 1, 2002. Under the settlement, ratepayers would continue to bear one-half of the costs incurred above the tolerance band.

Any awards associated with the CPIM normally are reflected annually in the purchased natural gas balancing account after the close of the annual period used to measure the CPIM, which is each 12-month period ending October 31. These awards are not included in earnings until approved by the CPUC.

We filed our annual CPIM report on May 30, 2003, recommending that we receive an award of $2.4 million. The report addresses natural gas procurement costs, interstate and intrastate transportation costs, and ratepayer savings and awards issued to us during the period from November 2001 through October 2002. On September 3, 2003, the ORA issued a report concurring with our recommended award. We anticipate CPUC approval before December 31, 2003.

In accordance with the Gas Accord, we stopped providing procurement service to noncore customers in March 2001. During the winter of 2000-2001 when there was a steep increase in natural gas prices, many noncore customers switched to core service in order to receive procurement service from us. In 2002, we filed a request with the CPUC to limit the number of noncore customers that could switch to core service because we were concerned that large increases in our natural gas supply portfolio demand would raise prices for all other core procurement customers and obligate us to reinforce our pipeline system to provide core service reliability on a short-term basis to serve this new load. Consistent with rules adopted for southern California natural gas utilities in 2002, we also have requested that electricity generation, cogeneration, enhanced oil recovery and refinery customers be prohibited from electing core service and that remaining noncore customers be limited to electing core service for a minimum five-year term.

Interstate and Canadian Natural Gas Transportation and Storage

Our interstate and Canadian natural gas transportation agreements with third party service providers are governed by tariffs that detail rates, rules and terms of service for the provision of natural gas transportation services to us on interstate and Canadian pipelines. United States tariffs are approved for each jurisdictional pipeline for service to all of its shippers, including us, by the FERC in a FERC ratemaking review process and the applicable Canadian tariffs by the Alberta Energy and Utilities Board and the National Energy Board. Our agreements with interstate and Canadian natural gas transportation service providers are administered as part of our core natural gas procurement business. Their purpose is to transport natural gas from the points at which we take delivery of natural gas typically in Canada, the Rocky Mountains and the southwestern United States to the points at which our natural gas transportation system begins.

Capacity Purchases on El Paso and Transwestern Pipelines. In July 2002, the CPUC ordered California investor-owned utilities to contract for additional amounts of El Paso pipeline capacity to gain firm access to the southwest natural gas producing basins. The CPUC believed that if the utilities had firm access rights, they would have been able to mitigate the gas price spikes that occurred during the energy crisis when shippers raised the price of gas at the California border. The CPUC pre-approved the costs of these contracts as just and reasonable. Since the July 2002 decision, we have signed contracts for capacity on the El Paso pipeline costing approximately $50.8 million for the period from November 2002 to December 2007. The July 2002 decision also ordered the California investor-owned utilities to retain their then-current interstate pipeline capacity levels and sell any excess capacity to third parties under short-term capacity release arrangements. It also ordered that, to the extent the California investor-owned utilities comply with the decision, they will be able to fully recover their costs associated with existing capacity contracts.

Under a previous CPUC decision, we could not recover in rates any costs paid to Transwestern for natural gas pipeline capacity through 1997. We pay approximately $22 million in annual reservation charges under the Transwestern contract. The Gas Accord provided for partial recovery of Transwestern costs beginning 1998. In June 2003, we reached a settlement with TURN that would allow us to fully recover Transwestern costs beginning in July 2003. The CPUC has not yet approved this settlement.

In December 2002, the CPUC granted our request to recover in rates El Paso pipeline capacity costs and prepayments made to El Paso from all natural gas customers. We began recovering these costs from all natural gas customers in March 2003. We have requested that the CPUC re-allocate all the costs, including Transwestern costs, assuming the CPUC approves our settlement with TURN, to our core customers, because the pipeline capacity is used to serve core customers. In the second phase of this proceeding, the CPUC is addressing other issues that relate to cost allocation of the interstate pipeline capacity among our customers, short-term capacity releases and details about the guaranteed rate recovery of the utilities costs for subscription to interstate pipeline capacity. Hearings in this second phase concluded in June 2003. We expect a CPUC decision in the second phase of the proceeding to be issued by the end of 2003. We do not expect the outcome of this matter to materially adversely affect our financial condition or results of operations.

El Paso Settlement. In June 2003, we, along with a number of other entities, entered into the El Paso settlement, to settle claims against El Paso relating to the sale or delivery of natural gas and/or electricity to or in the western United States, including claims that El Paso took actions that resulted in artificially inflated natural gas prices during the California energy crisis of 2000 and 2001. The El Paso settlement resolves all potential and alleged causes of action against El Paso for its part in alleged manipulation of natural gas and electricity commodity and transportation markets during the period from September 1996 to March 2003. Under the El Paso settlement s terms, El Paso will pay approximately $1.5 billion in cash and non-cash consideration. Of that total, approximately $352 million will be paid up front, another approximately $227 million (depending on the proceeds) will be paid from the sale of El Paso stock and approximately $875 million will be paid over 15 to 20 years. El Paso also agreed to a $125 million reduction in El Paso s long-term electricity supply contracts with the DWR and to provide pipeline capacity to California and to ensure specific reserve capacity for us, if needed. The exact amounts allocated to each entity are detailed in a master settlement agreement and delineated in an allocation agreement. The CPUC has issued a draft decision determining the precise means of allocation, under which our natural gas ratepayers would receive approximately $80 million and our electricity ratepayers would receive approximately $216 million. The CPUC expects to complete the final allocation of these refunds during the fourth quarter of 2003. The El Paso master settlement agreement is now pending approval by the FERC and the San Diego County Superior Court.

It is uncertain when or whether these required approvals will be obtained. The CPUC settlement agreement provides that the net after-tax amount of any consideration that we actually realize in cash related to the electricity portion of our refund (but not the natural gas refunds) will a reduce the outstanding balance of the new $2.21 billion after-tax regulatory asset if consistent with CPUC rules or orders.

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

We administer general and low-income energy efficiency programs, and have 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 we file an earnings claim in the annual earnings assessment proceeding, a forum for stakeholders to comment on, and for the CPUC to verify, our claim. On March 21, 2002, the CPUC eliminated the opportunity for these incentives in connection with the California investor-owned utilities 2002 energy efficiency programs. This decision does not preclude the opportunity to recover incentives in connection with previous years energy efficiency programs.

In October 2002, the CPUC opened a rulemaking proceeding to implement the non-bypassable natural gas public purpose program surcharge mandated by state legislation in 2001. The legislation requires all California natural gas users, even those users who are not utility customers, to fund public purpose energy efficiency, low-income energy efficiency, research and development and California Alternate Rates of Energy rate subsidies for qualifying low-income utility customers. The funds are collected by a surcharge on natural gas consumption, with utilities, many non-utility customers, and interstate pipelines remitting the surcharge revenues to the California State Board of Equalization. These funds are allocated to the natural gas public purpose programs by the CPUC. The CPUC rulemaking proceeding will formalize the processes for administering the natural gas consumption surcharge as well as identifying appropriate programs and funding levels for public purpose natural gas research and development programs.

In the CPUC settlement agreement, the CPUC states its intention that any operational mandate it imposes that requires us to expend funds or incur costs, including demand reduction or energy conservation programs, include timely rate recovery mechanisms.

In addition, pursuant to the CPUC settlement agreement, we will implement three environmental enhancement measures:

- we will encumber with conservation easements or donate approximately 140,000 acres of land to public agencies or non-profit conservation organizations;
- we will establish a California non-profit corporation to oversee the environmental enhancements associated with these lands and fund it with $70 million in cash over ten years, although we will be entitled to recover these payments in rates; and
- we will create a non-profit corporation funded with $15 million payable by us over five years dedicated to support research and investment in clean energy technology, primarily in our service territory.

Of the approximately 140,000 acres referred to in the first bullet, approximately 45,000 acres may be either donated or encumbered with conservation easements. The remaining land contains our or a joint licensee s hydroelectric generation facilities and may only be encumbered with conservation easements.

Under the CPUC settlement agreement, the CPUC agreed to act promptly on our pending ratemaking proceedings, including the annual earnings assessment proceeding applications. We do not expect that the outcome of these proceedings will materially adversely affect our financial condition or results of operations.

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 that 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.

General

We are subject to a number of federal, state and local laws and requirements relating to the protection of the environment and the safety and health of our personnel and the public. 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, remediation of and emergency response in connection with, hazardous, toxic and radioactive substances; 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. These laws and requirements also may require us, under certain circumstances, to interrupt or curtail operations. To comply with these laws and requirements, we may need to spend substantial amounts from time to time to construct, acquire, modify or replace equipment, acquire permits and/or marketable allowances or other emission credits for facility operations and clean up or decommission waste disposal areas at our current or former facilities and at third-party sites where we may have disposed of wastes.

In the past, we generally have recovered the costs of complying with environmental laws and regulations in our rates. In 1994, the CPUC established a ratemaking mechanism for hazardous waste remediation costs under which we are authorized to recover costs for environmental claims (*e.g.*, for cleaning up our facilities and sites where we have sent hazardous substances) from ratepayers. That mechanism assigns 90% of the hazardous substance cleanup costs to our ratepayers and 10% to us without a review of the costs of the underlying activities. Expenditures for environmental costs in the future are likely to be significant. However, based on our past experience, we believe that we will be able to recover most of these costs from our ratepayers and insurers. We cannot assure you, however, that these costs will not be material, or that we will be able to recover our costs in the future.

Air Quality

Our generation plants and pipeline operations 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, sulphur dioxide, nitrogen oxide and particulate matter. Fossil fuel-fired electric utility plants and gas compressor stations used in our pipeline operations are 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 nitrogen oxide, sulphur dioxide, mercury and carbon dioxide. Some of these proposals would allow the use of trading mechanisms to achieve or maintain compliance with the proposed rules.

As a result of our divestiture of most of our fossil fuel-fired and geothermal generation facilities, our nitrogen oxide emission reduction compliance costs have been reduced significantly. Under the California Clean Air Act and the Federal Clean Air Act, two of the local air districts in which we own and operate fossil fuel-fired generation facilities have adopted final rules that require reductions in nitrogen oxide emissions from the facilities of approximately 90% by 2004 (with numerous interim compliance deadlines).

The Gas Accord authorized $42 million to be included in rates through 2002 for gas nitrogen oxide retrofit projects related to natural gas compressor stations on our Line 300, which delivers gas from the southwest. The Gas Accord settlement agreement provides for recovery of these costs in rates through 2003, and the amended Gas Accord II application requests recovery of all of our actually incurred costs for these projects in rates through 2004. Several air districts are considering nitrogen oxide rules that would apply to our other natural gas compressor stations in California. Eventually, the rules are likely to require nitrogen oxide reductions of up to 80% at many of these natural gas compressor stations. Substantially all these costs will be capital costs.

In addition, current regulatory initiatives, particularly at the federal level, could increase our compliance costs and capital expenditures to comply with laws relating to emissions of carbon dioxide and other greenhouse gases, particulates and other pollutants. If enacted, these laws could require us to install additional pollution controls, purchase emission various allowances or curtail operations. Although associated costs could be material, we expect that we would be able to recover these costs from ratepayers. We 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 sulphur dioxide emissions. Implementation of the acid rain provisions is achieved through a total cap on sulphur dioxide emissions from affected generating units and an allocation of marketable sulphur dioxide allowances to each affected generating unit.

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 U.S. Environmental Protection Agency, or the EPA. Our generation facilities are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. Our steam-electric generation facilities comply in all material respects with the discharge constituents standards and the thermal standards. In addition, under the Federal Clean Water Act, we are required to demonstrate that the location, design, construction and capacity of generation facility cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts at our existing water-cooled thermal plants. We have submitted detailed studies of each steam-electric generation facility s intake structure to various governmental agencies and each power plant s existing intake structure was found to meet the best technology available requirements.

Our Diablo Canyon power plant employs a once-through cooling water system that is regulated under a NPDES permit issued by the Central Coast Board. This permit allows our Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the 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, our Diablo Canyon power plant s discharge was not protective of beneficial uses.

In October 2000, we and the Central Coast Board reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that our discharge of cooling water from our Diablo Canyon power plant protects beneficial uses and that the intake technology meets the best technology available requirements. As part of the Central Coast settlement agreement, we will take measures to preserve certain acreage north of the plant and will fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the Central Coast settlement agreement. On May 5, 2003, the bankruptcy court authorized us to sign the final Central Coast settlement agreement. On June 17, 2003, the Central Coast settlement agreement was fully executed by us, the Central Coast Board, and the California Attorney General s Office. In order for the Central Coast settlement agreement to become effective, among other things, the Central Coast Board must renew our Diablo Canyon power plant s NPDES permit. However, at its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the Central Coast settlement agreement accepted in March 2003 and the Central Coast Board requested its staff to develop additional information on possible mitigation measures. The California Attorney General filed a claim in our Chapter 11 case on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with our Diablo Canyon power plant s operation of its cooling water system. We are seeking withdrawal of this claim from our Chapter 11 case.

In addition, 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 electricity generation facilities using over 50 million gallons per day, typically including some form of once-through cooling. Our Diablo Canyon power plant, Hunters Point and Humboldt Bay are among an estimated 539 generation facilities 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.

We believe the ultimate outcome of these water quality matters will not have a material impact on our financial condition 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 or other water discharge requirements on our 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 our 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. We 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 our facilities or operations.

Hazardous Waste Compliance and Remediation

Our facilities are subject to the requirements issued by the EPA under the Resource Conservation and Recovery Act, or RCRA, and CERCLA, as well as 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 our operations, we generate waste that falls within CERCLA s definition of a hazardous substance and, as a result, have 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.

We assess, on an ongoing basis, measures that may be necessary to comply with federal, state and local laws and regulations related to hazardous materials and hazardous waste compliance and remediation activities. We have a comprehensive program to comply with hazardous waste storage, handling and disposal requirements issued by the EPA under RCRA and CERCLA, state hazardous waste laws and other environmental requirements.

We have been, and may be, required to pay for environmental remediation at sites where we have 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 we store, recycle and dispose of potentially hazardous materials. Under federal and California laws, we may be responsible for remediation of hazardous substances even if we did not deposit those substances on the site.

Operations at our current and former generation facilities may have resulted in contaminated soil or groundwater. Although we sold most of our geothermal generation facilities and most of our fossil fuel-fired plants, in many cases we retained pre-closing environmental liability under various environmental laws. We currently are 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, we 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 our electricity distribution system.

We are 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 from the mid-1800s through the early 1900s, manufactured gas plants produced lampblack and tar residues. The lampblack and tar residues are byproducts of a process that we, our 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), our manufactured gas plants were removed from service. The residues that may remain at some sites contain chemical compounds that now are classified as hazardous. We own all or a portion of 28 manufactured gas plant sites. We have a program, in cooperation with environmental agencies, to evaluate and take appropriate action to mitigate any potential health or environmental hazards at these sites. We spent approximately $4 million in 2002 and expect to spend approximately $11 million in 2003 on such projects. We expect 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 our service territory are now owned by others, and it is possible that we may incur cleanup costs related to these sites in the future if hazardous substances for which we have liability are found.

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

In addition, we have been named as a defendant in several civil lawsuits in which plaintiffs allege that we are responsible for performing or paying for remedial action at sites that we no longer own or never owned. Remedial actions may include investigations, health and ecological assessments and removal of wastes.

The cost of environmental remediation is difficult to estimate. We record an environmental remediation liability when site assessments indicate remediation is probable and we can estimate a range of reasonably likely cleanup costs. We review our remediation liability quarterly for each site where we may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure using current technology, enacted laws and regulations, experience gained at similar sites and 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, we record the costs at the lower end of this range. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning our responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. We estimate the upper limit of the range of costs using assumptions least favorable to us based upon a range of reasonably possible outcomes.

We had an undiscounted environmental remediation liability of $302 million at June 30, 2003, and $331 million at December 31, 2002. During the six months ended June 30, 2003, the liability was reduced by $29 million primarily due to a reassessment of the estimated cost of remediation. The $302 million accrued at June 30, 2003, includes $105 million related to the pre-closing remediation liability associated with divested generation facilities, and $197 million related to remediation costs for those generation facilities that we still own, natural gas gathering sites, compressor stations, third-party disposal sites, and manufactured gas plant sites that are either owned by us or are the subject of remediation orders by environmental agencies or claims by the current owners of the former gas plant sites. Of the $302 million environmental remediation liability, we have recovered $155 million through rates charged to our customers, and expect to recover approximately $93 million of the balance in future rates. Any amounts collected in excess of our ultimate obligations may be subject to refunds to ratepayers. We also are recovering our costs from insurance carriers and from other third parties whenever it is possible. Our future undiscounted environmental remediation liability could increase to as much as $418 million if the other potentially responsible parties are not financially able to contribute to these costs, the extent of contamination or necessary remediation is greater than anticipated, or we are found to be responsible for cleanup costs at additional sites.

The California Attorney General filed claims in our Chapter 11 case on behalf of various state environmental agencies for environmental remediation at numerous sites totaling approximately $770 million. For most of these sites, remediation is ongoing in the ordinary course of business or we are in the process of remediation in cooperation with the relevant agencies and other parties responsible for contributing to the cleanup. Other sites identified in the California Attorney General s claims may not, in fact, require remedial or cleanup actions. Our plan of reorganization provides that environmental claims in the regular course of business will not be discharged in our Chapter 11 case and pass through the Chapter 11 case unimpaired.

Potential Recovery of Hazardous Waste Compliance and Remediation Costs

To the extent we know or can estimate hazardous waste compliance costs, we intend to seek recovery for these costs in our 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 our ratepayers and 10% to us, without a reasonableness review of these costs or of underlying activities. Under the HWRC mechanism, 70% of the ratepayer portion of our cleanup costs is attributed to our natural gas rates and 30% is attributed to our electricity rates. Insurance recoveries are assigned 70% to us and 30% to ratepayers until both are reimbursed for the costs of pursuing insurance recoveries. The balance of insurance recoveries is allocated 90% to us and 10%

to ratepayers until we are reimbursed for our 10% share of cleanup costs. Any unallocated funds remaining are held for five years and then distributed 60% to ratepayers and 40% to us over the next five years. We can seek to recover hazardous substance cleanup costs under the HWRC in the rate proceeding that we deem most appropriate. In connection with electricity industry restructuring, the HWRC mechanism may no longer be used to recover electricity generation-related cleanup costs for contamination caused by events occurring after January 1, 1998.

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, or Nuclear Waste Act, 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 permanent disposal sites be in operation by 1998. Consistent with the law, we entered into a contract with the DOE providing for the disposal of the spent nuclear fuel and high-level radioactive waste from our 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. Further, under the DOE s current estimated acceptance schedule for spent fuel, our Diablo Canyon power plant s spent fuel may not be accepted by the DOE for interim or permanent storage before 2010, at the earliest. Under current operating procedures, we believe that our Diablo Canyon power plant s existing spent fuel pools have sufficient capacity to enable it to operate until the spring of 2007. It is likely that an interim or permanent DOE storage facility will not be available for our Diablo Canyon power plant s spent fuel by 2007. In December 2001, we filed a request with the NRC for a license to build a dry cask storage system to store spent fuel at our Diablo Canyon power plant, pending disposal or storage at a DOE facility. A hearing on several issues raised by objecting parties was held in May 2003 before an Atomic Safety and Licensing Board. On August 5, 2003 that body entered an order dismissing the contentions and terminating the proceeding. In October 2003, the NRC denied a petition for review filed by the objecting parties.

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, 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 our Diablo Canyon power plant s spent fuel would be accepted by Yucca Mountain for storage or disposal would be 2018.

In July 1988, the NRC gave us final approval to store radioactive waste from our retired nuclear generating unit, Humboldt Unit 3, at the plant until 2015 before ultimately decommissioning the unit. We have agreed to remove all spent fuel when the federal disposal site is available. In 1988, we completed the first step in the decommissioning of Humboldt Bay Unit 3 and placed the unit into 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 called a wet storage pool. The specially designed storage pool is constructed of steel-reinforced concrete and lined with stainless steel. We currently are 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. We anticipate that, if we were licensed to employ an on-site dry cask storage facility, we would receive a 20-year initial license for on-site dry cask storage with the opportunity to receive a 20-year renewal term.

Nuclear Decommissioning

Our nuclear power facilities are scheduled to begin decommissioning, for ratemaking purposes, in 2015 and are scheduled for completion in 2041. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use.

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). Our future estimate is based upon our 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. We plan to fund these costs from independent decommissioning trusts, which receive annual contributions discussed further below. We estimate 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 our 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. At June 30, 2003, the total nuclear decommissioning obligation accrued was $1.4 billion.

Since January 1, 1998, nuclear decommissioning 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. In 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 October 2, 2003, the CPUC issued a decision finding that the funds in the Diablo Canyon Nuclear Decommissioning Trusts are sufficient to pay for our Diablo Canyon power plant s eventual decommissioning. The decision also set the annual revenue requirement for the test period for Humboldt Bay Unit 3 at $18.5 million and granted our request to begin decommissioning Humboldt Bay Unit 3 in 2006 instead of 2015. The decision further granted our request for a revenue requirement of $8.3 million for Humboldt Bay Unit 3 SAFSTOR operating and maintenance costs, with attrition adjustments in 2004 and 2005 of $218,000 and $230,000, respectively. We collect this revenue requirement through a non-bypassable charge in electricity rates.

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. Amounts may not be released from the external trusts until authorized by the CPUC. At June 30, 2003, we had accumulated external trust funds with an estimated fair value of $1.4 billion, based on quoted market prices and net of deferred taxes on unrealized gains, to be used for the decommissioning of our nuclear facilities.

Electric and Magnetic Fields

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 our effort to educate the public about EMFs, we provide interested customers with information regarding the EMF exposure issue. We also provide 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 EMFs, 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. We 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 we must ultimately relocate existing power lines.

We currently are 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. We were one of the defendants 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.

Legal Proceedings

In addition to the following legal proceedings, we are involved in various legal proceedings in the ordinary course of our business.

Pacific Gas and Electric Company vs. Loretta M. Lynch et al.

On November 8, 2000, we filed a lawsuit in the U.S. District Court for the Northern District of California, or Northern District, against the CPUC commissioners. In this lawsuit we are seeking a declaration that the federally tariffed wholesale electricity costs that we had incurred to serve our customers are recoverable in retail rates under the federal filed rate doctrine, and asserting claims under the Takings, Commerce and Due Process Clauses of the United States Constitution. On January 29, 2001, our lawsuit was transferred to the U.S. District Court for the Central District of California, where a similar lawsuit filed by Southern California Edison Company was pending. On May 2, 2001, the court dismissed our complaint without prejudice to re-filing at a later date, on the ground that the lawsuit was premature, since two CPUC decisions referenced in the complaint had not become final under California law. The court rejected all of the CPUC s other arguments for dismissal of our complaint.

In August 2001, we re-filed our complaint in the Northern District based on our belief that the CPUC decisions referenced in the court s May 2001 order had become final under California law. On October 31, 2001, the CPUC moved to dismiss the action. While the motion was under submission, the parties filed cross-motions for summary judgment.

On July 25, 2002, the court denied the CPUC s motion to dismiss on all grounds as well as the parties motions for summary judgment. While the court agreed with our position that the filed rate doctrine applies to the federally-tariffed wholesale costs at which we had purchased electricity, it held that certain triable issues of fact precluded entry of summary judgment in our favor.

On August 23, 2002, the CPUC filed an appeal to the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit. Pursuant to our request, the Northern District certified the appeal as wholly without merit and, therefore, frivolous, and rejected the CPUC s request to stay the proceedings. On November 21, 2002, the

Ninth Circuit stayed the Northern District s proceedings pending the CPUC s appeal. The appeal was fully briefed and the Ninth Circuit heard oral argument on March 10, 2003.

As of July 10, 2003, the Ninth Circuit still not having issued a decision, we filed a motion to stay consideration of the appeal, in light of the CPUC settlement agreement, which would result in the dismissal of the filed rate case. On August 11, 2003, the Ninth Circuit issued an order staying proceedings in the filed rate case, and ordered the parties to file a status report by January 15, 2004.

Our complaint alleges that the wholesale electricity costs that we have prudently incurred are paid pursuant to filed tariffs that the FERC has authorized and approved, and that under the U.S. Constitution and numerous court decisions such costs cannot be disallowed by state regulators. Our complaint also alleges that, to the extent that we are denied recovery of these wholesale electricity costs by order of the CPUC, such action constitutes an unlawful taking and confiscation of our property. We argue that the CPUC s decisions are preempted by federal law under the filed rate doctrine, which requires the CPUC to allow us to recover in full our reasonable purchase costs incurred under lawful rates and tariffs approved by the FERC, a federal governmental agency. The complaint also pleads claims under the Commerce Clause and the Due Process Clause of the U.S. Constitution.

Under the CPUC settlement agreement, we will dismiss this lawsuit with prejudice on or as soon as practicable after the later of the effective date of our plan of reorganization and the date on which CPUC approval of the CPUC settlement agreement is no longer subject to appeal.

In re: Natural Gas Royalties Qui Tam Litigation

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

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

The complaints allege that the various defendants, most of whom are natural gas pipeline companies or their affiliates, incorrectly measured the volume and heating content of natural gas produced from federal or Indian leases. As a result, the relator alleges that the defendants underpaid, or caused others to underpay, the royalties that were due to the United States for the production of natural gas from those leases.

The complaints do not seek a specific dollar amount or quantify the royalties claim. The complaints seek unspecified treble damages, civil penalties and reasonable expenses associated with the litigation. The relator has filed a claim in our Chapter 11 case for $2.5 billion, $2.0 billion of which is based upon the relator s calculation of penalties against us.

We believe the allegations to be without merit and intend to present a vigorous defense. We believe that the ultimate outcome of the litigation will not have a material adverse effect on our financial condition or results of operations.

Diablo Canyon Power Plant

Our Diablo Canyon power plant employs a once-through cooling water system, which is regulated under a NPDES permit issued by the Central Coast Board. This permit allows our Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, our Diablo Canyon power plant s discharge was not protective of beneficial uses.

In October 2000, we reached a tentative settlement of this matter with the Central Coast Board pursuant to which the Central Coast Board agreed to find that our discharge of cooling water from our Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available as defined in the Federal Clean Water Act. As part of the Central Coast settlement agreement, we agreed to take measures to preserve certain acreage north of the plant and will fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the Central Coast settlement agreement. On May 5, 2003, the bankruptcy court authorized us to sign the final Central Coast settlement agreement. On June 17, 2003, the Central Coast settlement agreement was fully executed by us, the Central Coast Board, and the California Attorney General s Office. In order for the settlement to become effective, among other things, the Central Coast Board must renew our Diablo Canyon power plant s NPDES permit. However, at its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the Central Coast settlement agreement accepted in March 2003 and the Central Coast Board requested its staff to develop additional information on possible mitigation measures.

The California Attorney General has filed a claim in our Chapter 11 case on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with our Diablo Canyon power plant s operation of its cooling water system. We are seeking withdrawal of this claim.

On June 13, 2002, we received a draft enforcement order from the California Department of Toxic Substances Control, or DTSC, alleging that our Diablo Canyon power plant failed to maintain an adequate financial assurance mechanism to cover closure costs for its hazardous waste storage facility for several months after our Chapter 11 filing in 2001. The draft order sought $340,000 in civil penalties for the period during which we were unable to comply with the DTSC s requirements. The draft order also directed us to maintain appropriate financial assurance on a going forward basis. On September 4, 2002, we received a draft enforcement order from DTSC alleging a variety of hazardous waste violations at our Diablo Canyon power plant. This draft order sought $24,330 in civil penalties.

In April 2003, we signed a final settlement agreement with DTSC, under which we agreed to pay approximately $165,000 in civil penalties and approximately $30,000 in costs. We paid these amounts in May 2003. The California Attorney General filed a claim in our Chapter 11 case on behalf of DTSC, and we are currently seeking withdrawal of those portions of the claim relating to financial assurance and hazardous waste matters.

We believe that the ultimate outcome of these matters will not have a material adverse impact on our financial condition or results of operations.

Compressor Station Chromium Litigation

The following 14 civil suits are pending in several California courts against us relating to alleged chromium contamination: (1) *Aguayo v. Pacific Gas and Electric Company,* filed March 15, 1995, in Los Angeles County Superior Court, (2) *Aguilar v. Pacific Gas and Electric Company,* filed October 4, 1996, in Los Angeles County Superior Court, (3) *Acosta, et al. v. Betz Laboratories, Inc., et al.*, filed November 27, 1996, in Los Angeles County Superior Court, (4) *Adams v. Pacific Gas and Electric Company and Betz Chemical Company,* filed July 25, 2000, in Los Angeles County Superior Court, (5) *Baldonado v. Pacific Gas and Electric Company,* filed October 25, 2000, in Los Angeles County Superior Court, (6) *Gale v. Pacific Gas and Electric Company,* filed January 30, 2001, in Los Angeles County Superior Court, (7) *Fordyce v. Pacific Gas and Electric Company,* filed March 16, 2001, in San Bernardino Superior Court, (8) *Puckett v. Pacific Gas and Electric Company,* filed March 30, 2001, in Los Angeles County Superior Court, (9) *Alderson, et al. v. PG&E Corporation, Pacific Gas and Electric Company, Betz Chemical Company, et al.*, filed April 11, 2001, in Los Angeles County Superior Court, (10) *Bowers, et al. v. Pacific Gas and Electric Company, et al.*, filed April 20, 2001, in Los Angeles County Superior Court, (11) *Boyd, et al. v. Pacific Gas and Electric Company, et al.*, filed May 2, 2001, in Los Angeles County Superior Court, (12) *Martinez, et al. v. Pacific Gas and Electric Company,* filed June 29, 2001, in San Bernardino County Superior Court, (13) *Miller v. Pacific Gas and Electric Company,* filed November 21, 2001, in Los Angeles County Superior Court, and (14) *Lytle v. Pacific Gas and Electric Company,* filed March 22, 2002, in Yolo County Superior Court.

All of these civil actions are now pending in the Los Angeles Superior Court, except the Lytle case, which is pending in Yolo County. Currently there are approximately 1,200 plaintiffs in the chromium litigation cases. Approximately 1,260 individuals have filed proofs of claim in our Chapter 11 case, most of whom are plaintiffs in the chromium litigation. Approximately 1,035 claimants have filed proofs of claim requesting approximately $580 million in damages and another approximately 225 claimants have filed claims for an unknown amount.

In general, plaintiffs and claimants allege that exposure to chromium at or near our gas compressor stations located at Kettleman and Hinkley, California, and the area of California near Topock, Arizona caused personal injuries, wrongful death, or other injury and seek related damages. The bankruptcy court has granted certain claimants motion for relief from stay so that the state court lawsuits pending before our Chapter 11 filing can proceed.

We are responding to the suits in which we have been served and are asserting affirmative defenses. We will pursue appropriate legal defenses, including the statute of limitations, exclusivity of workers compensation laws, and factual defenses, including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged.

To assist in managing and resolving litigation with this many plaintiffs, the parties agreed to select plaintiffs from the *Aguayo, Acosta* and *Aguilar* cases for a test trial. Ten of these initial trial plaintiffs were selected by plaintiffs counsel, seven plaintiffs were selected by defense counsel, and one plaintiff and two alternates were selected at random. We have filed 13 summary judgment motions challenging the claims of the test trial plaintiffs. Two of these motions are scheduled to be heard in December 2003 and two of these motions are scheduled to be heard in January 2004. We have also filed a motion to dismiss the complaint in one of the cases that is scheduled for hearing on November 14, 2003. The trial of the 18 test cases is scheduled to begin in March 2004.

We have recorded a reserve in our financial statements in the amount of $160 million for these matters. We believe that, in light of the reserves that have already been accrued with respect to this matter, the ultimate outcome of this matter will not have a material adverse impact on our financial condition or future results of operations.

California Attorney General Complaint

On January 10, 2002, the California Attorney General filed a complaint in the San Francisco Superior Court against our directors, as well as against Corp and its directors, based on allegations of unfair or fraudulent business acts or practices in violation of Section 17200 of the California Business and Professions Code, or B&P Code Section 17200. We refer to this case as the California Attorney General s case. Among other allegations, the California Attorney General alleged that past transfers of money from us to Corp, and allegedly from Corp to other of its affiliates, violated various conditions established by the CPUC in decisions approving Corp s formation as a holding company. The California Attorney General also alleged that Corp s December 2000 and January and February 2001 ringfencing transactions, by which Corp s subsidiaries complied with credit rating agency criteria to establish independent credit ratings, violated the holding company conditions. The California Attorney General alleged that these ringfencing transactions included conditions that restricted NEG s ability to provide any funds to Corp through dividends, capital distributions or similar payments, reducing Corp s cash and thereby impairing Corp s ability to comply with the capital requirements condition and subordinating our interests to the interests of Corp and its other affiliates. On January 9, 2002, the CPUC issued a decision interpreting the capital requirements condition (which it terms 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 California investor-owned energy utilities and their parent holding companies had opposed the broader interpretation, first contained in a proposed decision released for comment on December 26, 2001, 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 three California investor-owned utilities and their parent holding companies appealed the CPUC s interpretation of the capital requirements condition to various state appellate courts. The CPUC moved to consolidate all proceedings. The CPUC s request was granted and all the petitions are now before the First Appellate District in San Francisco, California.

The complaint seeks injunctive relief, the appointment of a receiver, restitution in an amount according to proof, civil penalties of $2,500 against each defendant for each violation of B&P Code Section 17200, that the total penalty not be less than $500 million, and costs of suit.

In addition, the California Attorney General alleges that, through our Chapter 11 case, we and Corp engaged in unlawful, unfair, and fraudulent business practices by seeking to implement the transactions proposed in the original plan of reorganization filed in our Chapter 11 case in which we sought to disaggregate our businesses. The California Attorney General s complaint also seeks restitution of assets allegedly wrongfully transferred to Corp from us.

In February 2002, Corp filed a notice of removal in the bankruptcy court to transfer the California Attorney General s complaint to the bankruptcy court, as well as a motion to dismiss, or in the alternative, to stay, the California Attorney General s complaint with the bankruptcy court. Subsequently, the California Attorney General filed a motion to remand the action to state court. In June 2002, the bankruptcy court held that federal law preempted the California Attorney General s allegations concerning Corp s participation in our Chapter 11 case. The bankruptcy court directed the California Attorney General to file an amended complaint omitting these allegations and remanded the amended complaint to the San Francisco Superior Court. Both parties appealed the bankruptcy court s remand order to the Northern District. On October 8, 2003, the Northern District reversed, in part, the bankruptcy court s June 2002 decision and ordered the California Attorney General s restitution claims sent back to the bankruptcy court. The Northern District found that these claims, estimated along with certain claims of the City and County of San Francisco that are coordinated with the Behr case discussed below at approximately $5.0 billion, are the property of our estate and are therefore properly within the bankruptcy court s jurisdiction. Under our plan of reorganization, we would release these claims. The Northern District also affirmed, in part, the bankruptcy court s June 2002 decision and found that the California Attorney General s civil penalty and injunctive relief claims under B&P Code Section 17200 could be resolved in San Francisco Superior Court. No proceedings have been scheduled in the bankruptcy court regarding the restitution claims.

On August 9, 2002, the California Attorney General filed its amended complaint in the San Francisco Superior Court, omitting the allegations concerning Corp s participation in our Chapter 11 case. Corp and the directors named in the complaint have filed a motion to strike certain allegations of the amended complaint. In February 2003, the court denied the motions to strike on the grounds that they were premature, and stated that it would defer making a judgment on the merits of the defendants arguments until the factual context of the case is more fully developed. A status conference has been scheduled for December 18, 2003.

Cynthia Behr v. PG&E Corporation, et al.

On February 14, 2002, this complaint was filed by a private plaintiff in Santa Clara Superior Court against Corp, its directors, our directors and other parties, also alleging a violation of B&P Code Section 17200. The allegations of the complaint are similar to the allegations contained in the California Attorney General s complaint but also include allegations of civil conspiracy, fraudulent transfer and violation of the California bulk sales laws. Plaintiff requests the same remedies as the California Attorney General s case and in addition requests damages, attachment and restraints upon the transfer of defendants property. On March 8, 2002, Corp filed a notice of removal in the bankruptcy court to transfer the complaint to the bankruptcy court. Subsequently, the plaintiff filed a motion to remand the action to state court.

In its June 2002 ruling referred to above as to the California Attorney General s case, the bankruptcy court retained jurisdiction over Behr s fraudulent transfer claim and bulk sales claim, finding them to belong to our Chapter 11 estate. The bankruptcy court remanded Behr s B&P Code Section 17200 claim to the Santa Clara Superior Court. Both parties have appealed the bankruptcy court s remand order to the Northern District. On October 8, 2003, the Northern District reversed, in part, the bankruptcy court s June 2002 decision and ordered Behr s restitution claims to be sent back to the bankruptcy court. The Northern District found that these claims are the property of our estate and are therefore properly within the bankruptcy court s jurisdiction. Under our plan of reorganization, we would release these claims. The Northern District also affirmed, in part, the bankruptcy court s June 2002 decision and found that Behr s injunctive relief claims under Section 17200 could be resolved in San Francisco Superior Court. No proceedings have been scheduled in the bankruptcy court regarding the restitution claims.

Following remand, Corp moved to have the Behr case coordinated with a case filed in San Francisco Superior Court against Corp by the City and County of San Francisco, and the People of the State of California which, among other things, alleged a violation of B&P Code Section 17200. That motion was granted, and the Behr case is now proceeding in San Francisco Superior Court.

In April 2003, the San Francisco Superior Court dismissed Behr s civil conspiracy cause of action. Behr has filed an amended complaint asserting a B&P Code Section 17200 cause of action and another conspiracy cause of action. A status conference has been scheduled for December 18, 2003.

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

On February 27, 2002, a group of 25 ratepayers filed a complaint against us at the CPUC demanding an immediate reduction of approximately $0.035 per kWh in allegedly excessive electricity rates and a refund of alleged recent over-collections in electricity revenue since June 1, 2001. The complaint claims that electricity rate surcharges adopted in the first quarter of 2001 due to the high cost of wholesale electricity, which increased the average electricity rate by $0.04 per kWh, became excessive later in 2001. The only alleged over-collection amount calculated in the complaint is approximately $400 million during the last quarter of 2001. On April 2, 2002, we filed an answer, arguing that the complaint should be denied and dismissed immediately as an impermissible collateral action and on the basis that the alleged facts, even if assumed to be true, do not establish that currently authorized electricity rates are not reasonable.

On May 10, 2002, we filed a motion to dismiss the complaint. The CPUC has not yet issued a decision. However, under the CPUC settlement agreement the CPUC acknowledges and agrees that the surcharge and revenues accrued or collected by us through and including December 31, 2003 are the property of our Chapter 11 estate, have been or will be used for utility purposes, including to pay creditors in our Chapter 11 case, have been included in our retail electricity rates consistent with state and federal law and are not subject to refund.

MANAGEMENT

As of October 15, 2003, the names, ages and positions of the members of our board of directors and our executive officers were as follows:

Name	Age	Position
Robert D. Glynn, Jr.	60	Chairman of the Board
David R. Andrews	61	Director
David A. Coulter	56	Director
C. Lee Cox	62	Director
William S. Davila	72	Director
David M. Lawrence, MD	63	Director
Mary S. Metz	66	Director
Carl E. Reichardt	72	Director
Barry Lawson Williams	59	Director
Gordon R. Smith	55	Director, President and Chief Executive Officer
Kent M. Harvey	45	Senior Vice President, Chief Financial Officer and Treasurer
Roger J. Peters	53	Senior Vice President and General Counsel
James K. Randolph	59	Senior Vice President and Chief of Utility Operations
Daniel D. Richard, Jr	53	Senior Vice President, Public Affairs
Gregory M. Rueger	53	Senior Vice President, Generation and Chief Nuclear Officer

Robert D. Glynn, Jr. has been Chairman of our board of directors since January 1998 and has been one of our directors since 1995. Mr. Glynn has been one of our officers since January 1988. Mr. Glynn also has been Chairman of the Board, Chief Executive Officer and President of Corp since January 1998. Mr. Glynn has been a director and officer of Corp since 1996.

David R. Andrews has been one of our directors and a director of Corp since 2000. Mr. Andrews is Senior Vice President Government Affairs, General Counsel and Secretary of PepsiCo, Inc. (global snack and beverage), and has held that position since February 2002. Before joining PepsiCo, Mr. Andrews was a partner in the law firm of McCutchen, Doyle, Brown & Enersen, LLP from May 2000 to January 2002 and from 1981 to July 1997. From August 1997 to April 2000, he was the Legal Advisor to the U.S. Department of State and former Secretary Madeleine Albright. He also is a director of UnionBanCal Corporation.

David A. Coulter has been one of our directors and a director of Corp since 1996. Mr. Coulter is Vice Chairman of J.P. Morgan Chase & Co. (financial services and retail banking), and has held that position since January 2001. Before the merger with J.P. Morgan & Co. Incorporated, he was Vice Chairman of The Chase Manhattan Corporation from August 2000 to December 2000. He was a partner in the Beacon Group, L.P., an investment banking firm, from January 2000 to July 2000, and was Chairman and Chief Executive Officer of BankAmerica Corporation and Bank of America NT&SA from May 1996 to October 1998. He also is director of Strayer Education, Inc.

C. Lee Cox has been one of our directors and a director of Corp since 1996. Mr. Cox is retired Vice Chairman of AirTouch Communications, Inc. and retired President and Chief Executive Officer of AirTouch Cellular (cellular telephone and paging services). He was an executive officer of AirTouch Communications, Inc. and its predecessor, PacTel Corporation, from 1987 until his retirement in April 1997.

William S. Davila has been one of our directors since 1992 and a director of Corp since 1996. Mr. Davila is President Emeritus of The Vons Companies, Inc. (retail grocery). He was President of The Vons Companies from 1986 until his retirement in May 1992. He also is a director of The Home Depot, Inc.

David M. Lawrence, MD has been one of our directors since 1995 and a director of Corp since 1996. Dr. Lawrence was Chairman and Chief Executive Officer of Kaiser Foundation Health Plan, Inc. and Kaiser

Foundation Hospitals, and was an executive officer of those companies from 1991 until his retirement in 2002. He also is a director of Agilent Technologies Inc.

Mary S. Metz has been one of our directors since 1986 and a director of Corp since 1996. Dr. Metz is President of S. H. Cowell Foundation, and has held that position since January 1999. Before that date, she was Dean of University Extension, University of California, Berkeley from July 1991 to June 1998. She also is a director of Longs Drug Stores Corporation, SBC Communications Inc. and UnionBanCal Corporation.

Carl E. Reichardt has been one of our directors since 1985 and a director of Corp since 1996. Mr. Reichardt is the retired Vice Chairman of Ford Motor Company (automotive and financial services). He held that position from October 2001 to July 2003. He was Chairman of the Board and Chief Executive Officer of Wells Fargo & Company and Wells Fargo Bank, N.A. He also was an executive officer of Wells Fargo Bank, N.A. from 1978 until his retirement in December 1994. He also is a director of ConAgra Foods, Inc., Ford Motor Company and Newhall Management Corporation.

Barry Lawson Williams has been one of our directors since 1990 and a director of Corp since 1996. Since 1987, Mr. Williams has been President of Williams Pacific Ventures, Inc. (business investment and consulting). He also was interim President and Chief Executive Officer of the American Management Association, a management development organization, from November 2000 to June 2001. He also is a director of CH2M Hill Companies, Ltd., Newhall Management Corporation, R.H. Donnelley Corporation, The Simpson Manufacturing Company Inc., SLM Corporation and Synavant Inc.

Gordon R. Smith has been one of our directors since 1997. Mr. Smith also has been our President and Chief Executive Officer since June 1997. He has been one of our officers since June 1980. Mr. Smith also has been a Senior Vice President of Corp since January 1999.

Kent M. Harvey has been our Senior Vice President, Chief Financial Officer and Treasurer since July 1997. Mr. Harvey also was our Controller from January 2000 to October 2000.

Roger J. Peters has been our Senior Vice President since January 1999 and our General Counsel since July 1997. Mr. Peters also was our Vice President from July 1997 to December 1998.

James K. Randolph has been our Senior Vice President since July 1997 and our Chief of Utility Operations since May 2000. Mr. Randolph was our General Manager, Transmission, Distribution and Customer Service Business Unit from January 2000 to May 2000. He was our General Manager, Distribution and Customer Service Business Unit from July 1997 to January 2000.

Daniel D. Richard, Jr. has been our Senior Vice President of Public Affairs since May 1998. Mr. Richard was our Senior Vice President of Governmental and Regulatory Relations from July 1997 to April 1998. Mr. Richard also has been the Senior Vice President, Public Affairs of Corp since October 2000. He was Vice President of Governmental Relations of Corp from July 1997 to October 2000.

Gregory M. Rueger has been our Senior Vice President, Generation and Chief Nuclear Officer since April 2000. Mr. Rueger was our Senior Vice President and General Manager, Nuclear Power Generation Business Unit from November 1991 to April 2000.

All our directors serve until the next annual meeting of our shareholders, or until their successors are elected and qualified, except in the case of death, resignation or removal of the director. All our officers serve at the pleasure of our board of directors.

DESCRIPTION OF THE DEBT SECURITIES

This prospectus describes certain general terms of the senior unsecured debt securities and the mortgage securities that we may sell from time to time under this prospectus, which we refer to collectively as the debt securities. We will describe the specific terms of each series of debt securities we offer in a prospectus supplement. The senior unsecured debt securities will be issued under a senior unsecured indenture and a supplemental indenture that we will enter into with , as trustee. The mortgage securities will be issued under a mortgage indenture and a supplemental indenture that we will enter into with , as trustee. We refer to the senior unsecured indenture and the mortgage indenture, as supplemented by any supplemental indentures, collectively as the indentures. We have summarized selected provisions of the indentures and the debt securities below. The information we are providing you in this prospectus concerning the debt securities and the indentures is only a summary of the information provided in those documents and the summary is qualified in its entirety by reference to the provisions of the indentures. You should consult the debt securities themselves and the indentures for more complete information on the debt securities as they, and not this prospectus or any applicable prospectus supplement, govern your rights as a holder. These documents are filed as exhibits to the registration statement of which this prospectus is a part. The indentures will be qualified under the Trust Indenture Act of 1939, as amended, or the Trust Indenture Act, and the terms of the debt securities will include those made part of the indentures by the Trust Indenture Act.

Capitalized terms used in the following summaries have the meanings specified in the applicable indenture unless otherwise defined below. In this section, references to we, our, ours and us refer only to Pacific Gas and Electric Company and not to any of its direct or indirect subsidiaries or affiliates.

General

The indentures will provide that the debt securities will be issued in one or more series, may be issued at various times, may have differing maturity dates and may bear interest at differing rates. We need not issue all debt securities of one series at the same time and, unless otherwise provided in the applicable prospectus supplement, we may reopen a series for issuances of additional debt securities of that series without the consent of the holders of the debt securities of that series. Unless otherwise described in the applicable prospectus supplement, the indentures will not limit the aggregate amount of debt we may incur.

The senior unsecured debt securities will be our senior unsecured obligations and will rank equally with all of our existing and future unsecured and unsubordinated debt. The senior unsecured debt securities will be effectively junior to all of our existing and future secured debt, including any mortgage securities described in the applicable prospectus supplement. Each series of our mortgage securities will effectively rank senior to our senior unsecured debt to the extent of the value of the property securing the mortgage securities.

Provisions of a Particular Series

The prospectus supplement applicable to each issuance of debt securities will specify, among other things:

- the title of the debt securities;
- whether the debt securities are senior unsecured debt securities or mortgage securities;
- the specific indenture under which the debt securities will be issued;
- any limitation on the aggregate principal amount of the debt securities;
- the price or prices at which we will sell the debt securities;
- the date or dates on which the principal of any of the debt securities is payable, including the maturity date, or how to determine those dates, and our right, if any, to extend those dates and the duration of any extension;
- the interest rate or rates of the debt securities, if any, which may be fixed or variable, or the method used to determine the rate or rates, and our ability to extend any interest payment periods and the duration of any extension;

the date or dates from which any interest will accrue, the dates on which we will pay interest on the debt securities and the regular record date for determining who is entitled to the interest payable on any interest payment date;

any periods or periods within which, or date or dates on which, the price or prices at which and the terms and conditions on which the debt securities may be redeemed, in whole or in part, at our option;

any obligation of ours to redeem, purchase or repay any of the debt securities pursuant to any sinking fund or other mandatory redemption provisions or at the option of the holder and the terms and conditions upon which the debt securities will be so redeemed, purchased or repaid;

the denominations in which we will authorize the debt securities to be issued, if other than $1,000 or integral multiples of $1,000;

whether we will offer the debt securities in the form of global securities and, if so, the name of the depositary for any global securities;

if the amount payable in respect of principal of or any premium or interest on any debt securities may be determined with reference to an index or other fact or event ascertainable outside the applicable indenture, the manner in which such amount will be determined;

the discharge and defeasance provisions applicable to that series of debt securities;

any events of default applicable to that series of debt securities;

covenants for the benefit of the holders of that series;

the currency, currencies or currency units in which the principal, premium, if any, and interest on the debt securities will be payable if other than U.S. dollars and the manner for determining the equivalent principal amount in U.S. dollars;

with respect to the mortgage securities, the property covered by the security interest, the priority of the security interest, the method of perfecting the security interest, any escrow arrangements related to the security interest, any terms for the release of property covered by the security interest and any terms under which additional mortgage securities may be issued; and

any other terms of the debt securities.

We may sell the debt securities at par or at a substantial discount below their stated principal amount. We will describe in the applicable prospectus supplement material U.S. federal income tax considerations, if any, and any other special considerations for any debt securities we sell that are denominated in a currency or currency unit other than U.S. dollars.

Unless otherwise indicated in the applicable prospectus supplement, there are no provisions in the indentures or the debt securities that require us to redeem, or permit the holders to cause a redemption of, those debt securities or that otherwise protect the holders in the event that we incur substantial additional indebtedness, whether or not in connection with a change in control.

Redemption

Any terms for the optional or mandatory redemption of the debt securities will be set forth in the applicable prospectus supplement. Unless otherwise indicated in the applicable prospectus supplement, debt securities will be redeemable by us only upon notice by mail not less than 30 nor more than 60 days before the date fixed for redemption and, if less than all the debt securities of a series are to be redeemed, the particular debt securities to be redeemed will be selected by the method provided for in the applicable prospectus supplement for any particular series, or in the absence of any such provision, by the applicable trustee in such manner as it deems fair and appropriate.

We have reserved the right to provide conditional redemption notices for redemptions at our option or for redemptions that are contingent upon the occurrence or nonoccurrence of an event or condition that cannot be ascertained prior to the time we are required to notify holders of the redemption. A conditional notice may state that if we have not deposited redemption funds with the applicable trustee or a paying agent on or before the redemption date or we have directed the applicable trustee or paying agent not to apply money deposited with it for redemption of debt securities, we will not be required to redeem the debt securities on the redemption date.

Modification of the Indentures; Waiver

Unless otherwise indicated in the applicable prospectus supplement, we and the applicable trustee may, with the consent of the holders of not less than a majority in aggregate principal amount of the debt securities of each affected series then outstanding under the applicable indenture, considered as one class, modify or amend that indenture, including the provisions relating to the rights of the holders of debt securities of that series. However, no modification or amendment may, without the consent of each holder of affected debt securities:

- change the stated maturity, reduce the principal amount or any premium payable on that debt security or reduce the interest rate of that debt security;
- reduce the amount of principal payable upon acceleration of the maturity of that debt security;
- change the currency of payment of principal of, or interest on, that debt security;
- impair the right to institute suit for the enforcement of any payment on or with respect to that debt security;
- reduce the percentage in principal amount of outstanding debt securities the consent of whose holders is required for modification or amendment of the applicable indenture;
- reduce the percentage of principal amount of outstanding debt securities necessary for waiver of compliance with certain provisions of the applicable indenture or for waiver of certain defaults;
- modify the provisions with respect to modification and waiver, except as provided in the applicable indenture;
- with respect to the mortgage indenture, reduce the quorum or voting requirements applicable to holders of the mortgage securities; or
- with respect to the mortgage indenture, permit the creation of any senior lien, terminate the lien of the mortgage indenture with respect to all or substantially all of the property covered by that lien or deprive the holders of the mortgage securities of the benefit of the lien of the mortgage indenture.

Unless otherwise indicated in the applicable prospectus supplement, the holders of not less than a majority in aggregate principal amount of the debt securities of each affected series then outstanding under the applicable indenture, voting as a single class, may waive compliance by us with certain provisions benefiting holders of debt securities of that series in that indenture or the applicable debt securities. The holders of not less than a majority in aggregate principal amount of the debt securities of any series outstanding under the applicable indenture may, on behalf of the holders of all of the debt securities of that series, waive any past default under that indenture with respect to that series and its consequences, except defaults in the payment of the principal of or any premium or interest on any debt securities of that series and defaults in respect of a covenant or provision in that indenture which cannot be modified, amended or waived without the consent of each holder of affected debt securities.

We and the applicable trustee may, without the consent of any holder of debt securities, amend the applicable indenture and the debt securities for certain reasons, including to:

- cure any ambiguity, defect or inconsistency;
- provide for assumption of our obligations by a successor;
- make changes that would provide the holders with additional benefits;
- make any change that will not adversely affect the interest of any holder of the debt securities in any material respect; and

comply with the requirements of the SEC to effect or maintain the qualification of the applicable indenture under the Trust Indenture Act.

Unless otherwise provided in the applicable prospectus supplement, in order to determine whether the holders of the requisite principal amount of the outstanding debt securities have taken an action under the applicable indenture as of a specified date:

the principal amount of an original issue discount security that will be deemed to be outstanding will be the amount of the principal that would be due and payable as of that date upon acceleration of the maturity to such date;

if, as of that date, the principal amount payable at the stated maturity of a debt security is not determinable, for example, because it is based on an index, the principal amount of that debt security deemed to be outstanding as of that date will be an amount determined in the manner prescribed in the applicable indenture for that debt security; and

debt securities owned by us or any other obligor upon the debt securities or any of their affiliates will be disregarded and deemed not to be outstanding.

Defeasance and Discharge

Discharge

If the applicable prospectus supplement so provides, any and all series of debt securities that have not already been delivered to the applicable trustee for cancellation and that have either become due and payable or are by their terms due and payable within one year (or scheduled for redemption within one year), will be discharged and canceled (except for certain specified surviving obligations) if, among other things, we:

irrevocably deposit with the applicable trustee money or U.S. government obligations, or a combination thereof as trust funds, in an amount sufficient to pay in full, the principal of (and premium, if any) and interest on all series of all applicable debt securities that have become due and payable, or will become due and payable or are to be called for redemption within one year;

pay all other sums required under the applicable indenture; and

deliver an officer s certificate and opinion of counsel to the applicable trustee stating that we have complied with all conditions precedent relating to the satisfaction and discharge of the applicable indenture.

Defeasance

If the applicable prospectus supplement so provides, we will be deemed to have paid and will be discharged from any and all obligations in respect of the debt securities of a series if certain conditions contained in the applicable indenture have been satisfied, and the provisions of that indenture will cease to be applicable with respect to the debt securities of that series (except for, among other matters, obligations to register the transfer of or exchange of the debt securities, replace stolen, lost or mutilated debt securities, maintain paying agencies and hold funds for payment in trust). Some of the conditions are as follows:

we have irrevocably deposited with the applicable trustee, in trust, money and/or certain U.S. government obligations that will provide money in an amount sufficient, in the opinion of a nationally recognized public accounting firm, to pay the principal of, premium, if any, and accrued interest on the debt securities of that series at the time the payments are due in accordance with the terms of the applicable indenture;

no event of default, or event that after the giving of notice or lapse of time or both would become an event of default, will have occurred and be continuing at the date of the deposit described in the immediately preceding bullet point or, with respect to certain events of bankruptcy, insolvency or reorganization in respect of us that would constitute an event of default, no event of default occurs during the period ending on the 90th day after the date of the deposit; and

- we have delivered to the applicable trustee an opinion of counsel, referred to as the tax opinion, to the effect that holders of debt securities of that series will not recognize income, gain or loss for federal income tax purposes as a result of the deposit, defeasance and discharge and will be subject to federal income tax on the same amounts and in the same manner and at the same times as would have been the case if the deposit, defeasance and discharge had not occurred, which tax opinion must be based upon a ruling of the Internal Revenue Service, or the IRS, to the same effect or a change in applicable federal income tax law or related treasury regulations after the date of the applicable indenture.

Under current applicable federal income tax law, such a defeasance would result in a taxable exchange for the holders of the debt securities; consequently, we cannot currently satisfy the conditions for a legal defeasance under current law.

Defeasance of Certain Covenants and Certain Events of Default

If the applicable prospectus supplement so provides, upon:

- the satisfaction of the conditions described in each of the bullet points under Defeasance and Discharge Defeasance above (other than the bullet point that describes the requirements to deliver a tax opinion); and

- our delivery to the applicable trustee of an opinion of counsel to the effect that the holders of debt securities of that series will not recognize income, gain or loss for federal income tax purposes as a result of the deposit and defeasance and will be subject to federal income tax on the same amount and in the same manner and at the same times as would have been the case if the deposit and defeasance had not occurred;

the covenants and events of default described in the applicable prospectus supplement will cease to be applicable.

If we must no longer comply with these covenants and events of default and the debt securities are declared due and payable because of the occurrence of an event of default that remains applicable, the amount of money and/or U.S. government obligations on deposit with the applicable trustee may not be sufficient to pay amounts due on the debt securities at the time of acceleration resulting from the event of default. In that event, we will remain liable for any deficiency.

Transfer and Exchange

Debt securities of any series will be exchangeable for other debt securities of the same series of any authorized denominations and of a like aggregate principal amount and tenor. Subject to the terms of the applicable indenture and the limitations applicable to global securities, debt securities may be presented for exchange or registration of transfer at the office of the registrar without service charge (unless otherwise indicated in the applicable prospectus supplement) but upon payment of any taxes and other governmental charges as described in the applicable indenture. Such transfer or exchange will be effected upon the applicable trustee, us or the registrar, as the case may be, being satisfied with the documents of title and identity of the person making the request.

In the event that we provide for any redemption of a series of debt securities in a prospectus supplement, we will not be required to issue, register the transfer of, or exchange any debt security of that series during a period beginning at the opening of business 15 days before the day of mailing of a notice of redemption of any such debt security called for redemption and ending at the close of business on the day of such mailing or register the transfer of or exchange any debt security of such series selected for redemption.

Global Securities

Unless otherwise indicated in the applicable prospectus supplement, each series of debt securities will initially be represented, in whole or in part, by one or more global securities, which will have an aggregate principal amount equal to that of the debt securities they represent. We will register each global security in the name of a nominee of The Depository Trust Company, as depository, and deposit the global security with, or on behalf of, the depositary. Each global security will bear a legend regarding the restrictions on exchanges and registration of transfer and other matters specified in a supplemental indenture to the indenture.

No global security may be exchanged for debt securities registered, and no transfer of a global security may be registered, in the name of any person other than the depositary for the global security or any nominee of the depositary, unless:

the depositary has notified us that it is unwilling or unable to continue as depositary for the global security or has ceased to be qualified to act as depositary;

a default has occurred and is continuing with respect to the debt securities represented by the global security; or

any other circumstances exist that may be described in the applicable supplemental indenture and prospectus supplement.

We will register all debt securities issued in exchange for a global security or any portion of a global security in the names specified by the depositary.

As long as the depositary or its nominee is the registered holder of a global security, the depositary or nominee will be considered the sole owner and holder of the global security and the debt securities that it represents. Except in the limited circumstances referred to above, owners of beneficial interests in a global security will not:

be entitled to have the global security or debt securities registered in their names;

receive or be entitled to receive physical delivery of certificated debt securities in exchange for a global security; and

be considered to be the owners or holders of the global security or any debt securities for any purpose under the indenture.

We will make all payments of principal, premium, and interest on a global security to the depositary or its nominee. The laws of some jurisdictions require that purchasers of securities take physical delivery of securities in definitive form. These laws make it difficult to transfer beneficial interests in a global security.

Ownership of beneficial interests in a global security will be limited to institutions that have accounts with the depositary or its nominee, referred to as participants, and to persons that may hold beneficial interests through participants. In connection with the issuance of any global security, the depositary will credit on its book-entry registration and transfer system the respective principal amounts of debt securities represented by the global security to the accounts of its participants. Ownership of beneficial interests in a global security will only be shown on records maintained by the depositary or the participant. Likewise, the transfer of ownership interests will be effected only through the same records. Payments, transfers, exchanges, and other matters relating to beneficial interests in a global security may be subject to various policies and procedures adopted by the depositary from time to time. Neither we, any applicable trustee nor any of our agents will have responsibility or liability for any aspect of the depositary s or any participant s records relating to, or for payments made on account of, beneficial interests in a global security, or for maintaining, supervising or reviewing any records relating to the beneficial interests.

Resignation or Removal of Trustees

The trustees under the indentures may resign at any time upon written notice to us but such resignation shall not take effect until the acceptance of appointment by a successor trustee. The trustees may be removed at any time by written notice delivered to the applicable trustee and us and signed by the holders of at least a majority in aggregate principal amount of each series of outstanding debt securities issued under the applicable indenture. In addition, under certain circumstances, we may remove a trustee, or any holder who has been a bona fide holder of a debt security for at least six months may seek a court order for the removal of the trustee under the applicable indenture and the appointment of a successor trustee. We must give notice of resignation and removal of a trustee or the appointment of a successor trustee to all holders of affected debt securities as provided in the indentures.

Trustees, Paying Agents and Registrars for the Debt Securities

will initially act as the trustee, paying agent and registrar under the unsecured indenture. will initially act as the trustee, paying agent and registrar under the mortgage indenture. We may change either the paying agent or registrar without prior notice to the holders of the debt securities, and we may act as paying agent. We and our affiliates maintain ordinary banking and trust relationships with a number of banks and trust companies, including and .

Governing Law

Each indenture and the debt securities will be governed by California law.

PLAN OF DISTRIBUTION

We may sell any series of debt securities being offered by this prospectus in one or more of the following ways from time to time:

- to underwriters or dealers for resale to the public or to institutional investors;
- directly to institutional investors; or
- through agents to the public or to institutional investors.

A prospectus supplement with respect to each series of debt securities will state the terms of the offering of the debt securities, including:

- the name or names of any underwriters or agents;
- the purchase price of the debt securities and the proceeds to be received by us from the sale;
- any underwriting discounts or agency fees and other items constituting underwriters or agents compensation;
- any initial public offering price;
- any discounts or concessions allowed or reallowed or paid to dealers; and
- any securities exchange on automated quotation system on which the debt securities may be listed.

If we use underwriters in the sale, the debt securities will be acquired by the underwriters for their own account and may be resold from time to time in one or more transactions, including:

- negotiated transactions;
- at a fixed public offering price or prices, which may be changed;
- at market prices prevailing at the time of sale;
- at prices based on prevailing market prices; or
- at negotiated prices.

The debt securities may be offered to the public either through underwriting syndicates represented by one or more managing underwriters or directly by one or more of those firms. The specific managing underwriter or underwriters, if any, will be named in the prospectus supplement relating to the particular debt securities together with the members of the underwriting syndicate, if any. Unless otherwise set forth in the applicable prospectus supplement, the obligations of the underwriters to purchase the particular debt securities will be subject to certain conditions precedent and the underwriters will be obligated to purchase all of the debt securities being offered if any are purchased.

We may sell the debt securities directly or through agents we designate from time to time. The applicable prospectus supplement will set forth the name of any agent involved in the offer or sale of the debt securities in respect of which such prospectus supplement is delivered and any commissions payable by us to such agent. Unless otherwise indicated in the applicable prospectus supplement, any agent will be acting on a best efforts basis for the period of its appointment.

Any underwriters, dealers or agents participating in the distribution of the debt securities may be deemed to be underwriters as defined in the Securities Act of 1933, or the Securities Act, and any discounts or commissions received by them on the sale or resale of the debt securities may be deemed to be underwriting discounts and commissions under the Securities Act. We may agree with the underwriters, dealers and agents to indemnify them against certain civil liabilities, including liabilities under the Securities Act or to contribute with respect to payments which the underwriters, dealers or agents may be required to make in respect of these liabilities.

Unless otherwise specified in a prospectus supplement, the debt securities will not be listed on a national securities exchange. Any underwriters to whom debt securities are sold by us for public offering and sale may make a market in the debt securities, but such underwriters will not be obligated to do so and may discontinue any market making at any time without notice.

To facilitate a debt securities offering, any underwriter may engage in over-allotment, stabilizing transactions, short covering transactions and penalty bids in accordance with Regulation M under the Securities Exchange Act of 1934.

Over-allotment involves sales in excess of the offering size, which creates a short position.

Stabilizing transactions permit bids to purchase the underlying debt security so long as the stabilizing bids to not exceed a specified maximum.

Short covering positions involve purchases of the debt securities in the open market after the distribution is completed to cover short positions.

Penalty bids permit the underwriters to reclaim a selling concession from a dealer when the debt securities originally sold by the dealer are purchase in a covering transaction to cover short positions.

These activities may cause the price of the debt securities to be higher than it otherwise would be. If commenced, these activities may be discontinued by the underwriters at any time.

We are currently contemplating issuing debt securities in an underwritten offering shortly after the registration statement containing this prospectus is declared effective by the SEC and substantially all conditions to the effectiveness of our plan of reorganization have been satisfied. The general terms of the debt securities are described in the section of this prospectus titled Description of the Debt Securities. We have not finally determined the amount, timing or terms of such an offering. Although the proceeds of this offering will initially be placed in an escrow account until our plan of reorganization becomes effective, the proceeds from this offering will be used to pay allowed claims in our Chapter 11 case. Other terms have not been determined at this time, but will be reflected in a prospectus supplement that will be filed with the SEC if and when we decide to proceed with this offering.

EXPERTS

The consolidated financial statements of Pacific Gas and Electric Company (a Debtor-in-Possession) and subsidiaries as of December 31, 2002 and 2001, and for each of the three years in the period ended December 31, 2002 included in this prospectus and the related consolidated financial statement schedule included elsewhere in the registration statement have been audited by Deloitte & Touche LLP, independent auditors, as stated in their reports appearing herein and elsewhere in the registration statement (which reports express an unqualified opinion and include explanatory paragraphs relating to (i) Pacific Gas and Electric Company s adoption of new accounting standards in 2001 referring to derivative contracts, and (ii) the ability of Pacific Gas and Electric Company to continue as a going concern) and have been so included in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

LEGAL MATTERS

The validity of the debt securities has been passed upon for us by . The validity of the debt securities will be passed upon for any agents, dealers or underwriters by their counsel named in the applicable prospectus supplement.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and special reports, information statements and other information with the SEC under File No. 001-2348. These SEC filings are available to the public over the Internet at the SEC s website at http://www.sec.gov. You may also read and copy any of these SEC filings at the SEC s public reference room at 450 Fifth Street, N.W., Room 1200, Washington D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on its public reference room.

We have incorporated by reference into this prospectus certain information that we file with the SEC. This means that we can disclose important business, financial and other information in this prospectus by referring you to the documents containing this information. All information incorporated by reference is deemed to be part of this prospectus except to the extent that the information is updated or superseded by the information contained in this prospectus (including specifically the consolidated financial statements at and for the years ended December 31, 2000, 2001 and 2002 and the six months ended June 30, 2002 and 2003) or the applicable prospectus supplement. Any information that we subsequently file with the SEC that is incorporated by reference, as described below, will automatically update and supersede any previous information that is part of this prospectus or the applicable prospectus supplement.

We incorporate by reference the documents listed below and any future filings we make with the SEC under Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 after the date of filing of the registration statement of which this prospectus is a part and before the termination of the offering of the debt securities offered hereby:

- our annual report on Form 10-K for the year ended December 31, 2002 and Amendments No. 1, 2 and 3 thereto;

- our definitive proxy statement dated March 21, 2003 filed in connection with our April 16, 2003 Annual Meeting of Shareholders;

- our quarterly report on Form 10-Q for the quarter ended March 31, 2003 and Amendment No. 1 to our quarterly report on Form 10-Q for the quarter ended March 31, 2003 and our quarterly report on Form 10-Q for the quarter ended June 30, 2003; and

- our current reports on Form 8-K filed with the SEC on January 6, 2003, March 6, 2003, March 12, 2003, March 17, 2003, April 2, 2003, April 21, 2003, April 24, 2003, June 20, 2003, July 8, 2003 (only Item 5), August 14, 2003, August 25, 2003, September 3, 2003 (only Item 5), September 10, 2003, September 16, 2003 (only Item 5), October 3, 2003 (only Item 5), October 15, 2003 (only Item 5) and October 24, 2003. (We do not incorporate by reference any information furnished pursuant to Items 9 or 12 in any future Form 8-K filing.)

The incorporation by reference of the filings listed above does not extend to any such filings made by Corp and not us or to any information in any filings jointly made by Corp and us regarding Corp or its other subsidiaries, but not regarding us.

You may request a copy of these filings and copies of the indentures and the other documents which establish the terms of the debt securities offered hereby at no cost by writing or contacting us at the following address:

The Office of the Corporate Secretary

Pacific Gas and Electric Company
P.O. Box 193722
San Francisco, CA 94119-3722
Telephone: (415) 267-7070
Facsimile: (415) 267-7268

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND

UNAUDITED CONDENSED FINANCIAL STATEMENTS

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INDEPENDENT AUDITORS REPORT

To the Board of Directors and Shareholders of

Pacific Gas and Electric Company

We have audited the accompanying consolidated balance sheets of Pacific Gas and Electric Company (a Debtor-in-Possession) and subsidiaries (the Company) as of December 31, 2002 and 2001, and the related consolidated statements of operations, cash flows, and shareholders equity for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the management of the Company. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2002 and 2001, and the results of its consolidated operations and its cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 of the Notes to the Consolidated Financial Statements, the Company adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by Statement of Financial Accounting Standards No. 138, Accounting for Certain Derivative Instruments and Hedging Activities, effective January 1, 2001.

The accompanying consolidated financial statements have been prepared on a going concern basis of accounting. As discussed in Notes 1 and 2 of the Notes to the Consolidated Financial Statements, the Company has incurred power purchase costs substantially in excess of amounts charged to customers in rates. On April 6, 2001, the Company sought protection from its creditors by filing a voluntary petition under provisions of Chapter 11 of the U.S. Bankruptcy Code. These matters raise substantial doubt about the Company s ability to continue as a going concern. Management s plans in regard to these matters are described in Note 2 of the Notes to the Consolidated Financial Statements. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

DELOITTE & TOUCHE LLP

San Francisco, California
February 24, 2003

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION

Consolidated Statements of Operations

(in millions)

	Six Months Ended June 30,		Year Ended December 31,		
	2003	**2002**	**2002**	**2001**	**2000**
	(unaudited)				
Operating Revenues					
Electric	$3,299	$3,971	$ 8,178	$ 7,326	$ 6,854
Natural gas	1,498	1,196	2,336	3,136	2,783
Total operating revenues	4,797	5,167	10,514	10,462	9,637
Operating Expenses					
Cost of electric energy	1,056	339	1,482	2,774	6,741
Deferred electric procurement cost					(6,465)
Cost of natural gas	806	513	954	1,832	1,425
Operating and maintenance	1,426	1,409	2,817	2,385	2,687
Depreciation, amortization, and decommissioning	605	565	1,193	896	3,511
Provision for loss on generation-related regulatory assets and undercollected purchased power costs					6,939
Reorganization professional fees and expenses	100	34	155	97	
Total operating expenses	3,993	2,860	6,601	7,984	14,838
Operating Income (Loss)	804	2,307	3,913	2,478	(5,201)
Reorganization interest income	27	41	71	91	
Interest income	4		3	32	186
Interest expense:					
Contractual interest expense	(377)	(443)	(839)	(810)	(619)
Noncontractual interest expense	(67)	(103)	(149)	(164)	
Other income (expense), net	7	(6)	(2)	(16)	(3)
Income (Loss) Before Income Taxes	398	1,796	2,997	1,611	(5,637)
Income tax provision (benefit)	125	731	1,178	596	(2,154)
Income Before Cumulative Effect of a Change in Accounting Principle	273	1,065	1,819	1,015	(3,483)
Cumulative effect of a change in accounting principle (net of income tax benefit of $1 million for six months ended June 30, 2003)	(1)				
Net Income (Loss)	272	1,065	1,819	1,015	(3,483)
Preferred dividend requirement	12	12	25	25	25
Income (Loss) Available for (Allocated to) Common Stock	$ 260	$1,053	$ 1,794	$ 990	$ (3,508)

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION

Consolidated Balance Sheets

(in millions)

	June 30, 2003	December 31, 2002	December 31, 2001
	(unaudited)		
ASSETS			
Current Assets			
Cash and cash equivalents	$ 3,700	$ 3,343	$ 4,341
Restricted cash	234	150	53
Accounts receivable:			
Customers (net of allowance for doubtful accounts of $62 million, $59 million and $48 million, respectively)	1,763	1,900	2,063
Related parties	18	17	18
Regulatory balancing accounts	142	98	75
Inventories:			
Gas stored underground and fuel oil	193	154	218
Materials and supplies	124	121	119
Income taxes receivable		50	
Prepaid expenses and other	83	110	80
Deferred income taxes		5	
Total current assets	6,257	5,948	6,967
Property, Plant and Equipment			
Electric	20,053	18,922	18,153
Gas	8,245	8,123	7,810
Construction work in progress	321	427	323
Total property, plant and equipment	28,619	27,472	26,286
Accumulated depreciation	(12,706)	(13,515)	(12,929)
Net property, plant and equipment	15,913	13,957	13,357
Other Noncurrent Assets			
Regulatory assets	1,922	2,011	2,283
Nuclear decommissioning funds	1,410	1,335	1,337
Other	511	1,300	1,325
Total other noncurrent assets	3,843	4,646	4,945
TOTAL ASSETS	$ 26,013	$ 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)

	June 30, 2003	December 31, 2002	December 31, 2001
	(unaudited)		
LIABILITIES AND SHAREHOLDERS EQUITY			
Liabilities Not Subject to Compromise			
Current Liabilities			
Long-term debt, classified as current	$ 591	$ 281	$ 333
Current portion of rate reduction bonds	290	290	290
Accounts payable:			
Trade creditors	460	380	333
Related parties	191	130	86
Regulatory balancing accounts	214	360	360
Other	369	374	289
Interest payable	148	126	26
Income taxes payable	51		295
Deferred income taxes	90		65
Other	458	625	599
Total current liabilities	2,862	2,566	2,676
Noncurrent Liabilities			
Long-term debt	2,429	2,739	3,019
Rate reduction bonds	1,019	1,160	1,450
Regulatory liabilities	939	1,461	1,485
Asset retirement obligations	1,395		
Deferred income taxes	1,464	1,485	1,028
Deferred tax credits	135	144	153
Other	1,783	1,274	1,239
Total noncurrent liabilities	9,164	8,263	8,374
Liabilities Subject to Compromise			
Financing debt	5,604	5,605	5,651
Trade creditors	3,852	3,786	5,733
Total liabilities subject to compromise	9,456	9,391	11,384
Commitments and Contingencies			
Preferred Stock With Mandatory Redemption Provisions			
6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009	137	137	137
Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely PG&E Subordinated Debentures			
7.90%, 12,000,000 shares, due 2025			300
Shareholders Equity			
Preferred stock without mandatory redemption provisions			
Nonredeemable, 5.00% to 6.00%, outstanding 5,784,825 shares	145	145	145
Redeemable, 4.36% to 7.04%, outstanding 5,973,456 shares	149	149	149
Common stock, $5 par value, authorized 800,000,000 shares, issued and outstanding 321,314,760 shares	1,606	1,606	1,606

Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)	(475)
Additional paid-in capital	1,964	1,964	1,964
Reinvested earnings (accumulated deficit)	1,065	805	(989)
Accumulated other comprehensive loss	(60)		(2)
Total shareholders equity	4,394	4,194	2,398
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY	$26,013	$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)

	Six Months Ended June 30,		Year Ended December 31,		
	2003	2002	2002	2001	2000
	(unaudited)				
Cash Flows from Operating Activities					
Net income (loss)	$ 272	$ 1,065	$ 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	605	565	1,193	896	3,511
Deferred income taxes and tax credits, net	101	(123)	378	(306)	(930)
Other deferred charges and noncurrent liabilities	284	363	102	(954)	480
Gain on sale of assets	(7)				
Reversal of ISO accrual		(970)	(970)		
Cumulative effect of a change in accounting principle	2				
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	(84)	(1)	(97)	(3)	(8)
Accounts receivable	84	99	212	105	(507)
Income tax receivable			(50)	1,120	(1,120)
Inventories	(42)	47	62	(57)	14
Accounts payable	252	97	198	1,312	3,063
Accrued taxes	51	493	(295)	295	(118)
Regulatory balancing accounts, net	(190)	(47)	(23)	311	(410)
Other working capital	(79)	(34)	11	711	111
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	(62)	(947)	(1,442)	(16)	
Other, net	17	23	36	336	(522)
Net cash provided by operating activities	1,204	630	1,134	4,765	555
Cash Flows from Investing Activities					
Capital expenditures	(730)	(743)	(1,546)	(1,343)	(1,245)
Proceeds from sale of assets, net	11	5	11		6
Other, net	13	13	26	5	32
Net cash provided (used) by investing activities	(706)	(725)	(1,509)	(1,338)	(1,207)
Cash Flows from Financing Activities					
Net borrowings (repayments) under credit facilities and short-term borrowing				(28)	2,630
Long-term debt issued					680
Long-term debt matured, redeemed, or repurchased		(333)	(333)	(111)	(307)
Rate reduction bonds matured	(141)	(141)	(290)	(290)	(290)
Common stock repurchased					(275)
Dividends paid					(475)
Other, net		(1)		(1)	(26)

Net cash provided (used) by financing activities	(141)	(475)	(623)	(430)	1,937
Net change in cash and cash equivalents	357	(570)	(998)	2,997	1,285
Cash and cash equivalents at beginning of period	3,343	4,341	4,341	1,344	59
Cash and cash equivalents at end of period	3,700	3,771	3,343	4,341	1,344
Supplemental disclosures of cash flow information					
Cash received for:					
Reorganization interest income	$ 21	$ 42	$ 75	$ 87	$
Cash paid for:					
Interest (net of amounts capitalized)	341	683	1,105	361	587
Income taxes paid (refunded), net	(32)	353	1,186	(556)	
Reorganization professional fees and expenses	71	9	99	19	
Supplemental disclosures of noncash investing and financing activities					
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities	127	(297)	419	11,400	

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION

Consolidated Statements of Shareholders Equity

(in millions, except share amount)

	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders Equity	Preferred Stock Without Mandatory Redemption Provisions	Comprehensive Income (Loss)
Balance at December 31, 1999	$ 1,606	$ 1,964	$ (200)	$ 2,107	$	$ 5,477	$ 294	
Net loss				(3,483)		(3,483)		$ (3,483)
Common stock repurchased (11,853,448) shares			(275)			(275)		
Cash dividends declared								
Preferred stock				(25)		(25)		
Common stock				(578)		(578)		
Balance at December 31, 2000	1,606	1,964	(475)	(1,979)		1,116	294	
Net income				1,015		1,015		$ 1,015
Cumulative effect of adoption of SFAS No. 133					90	90		90
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133					(5)	(5)		(5)
Net reclassification to earnings					(85)	(85)		(85)
Foreign currency translation adjustments					(2)	(2)		(2)
Comprehensive income								$ 1,013
Preferred stock dividend requirement				(25)		(25)		
Balance at December 31, 2001	1,606	1,964	(475)	(989)	(2)	2,104	294	
Net income				1,819		1,819		$ 1,819
Foreign currency translation adjustments					2	2		2
Comprehensive income								$ 1,821
Preferred stock dividend requirement				(25)		(25)		
Balance at December 31, 2002	1,606	1,964	(475)	805		3,900	294	
Net income (unaudited)				272		272		272
Retirement plan remeasurement (unaudited)					(60)	(60)		(60)
Comprehensive income (unaudited)								212
				(12)		(12)		

Preferred stock dividend requirement (unaudited)							
Balance at June 30, 2003	$ 1,606	$ 1,964	$ (475)	$ (1,065)	$ (60)	$ 4,100	$ 294

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED

DECEMBER 31, 2002, 2001 AND 2000

Note 1: General

Organization and Basis of Presentation

Pacific Gas and Electric Company (PG&E), a wholly owned subsidiary of PG&E Corporation, was incorporated in 1905 and is an operating regulated electric and natural gas distribution and transmission utility company. As discussed further in Note 2, on April 6, 2001, PG&E filed a voluntary petition for relief under the provisions of Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Pursuant to Chapter 11 of the Bankruptcy Code (Chapter 11), PG&E retains control of its assets and is authorized to operate its business as a debtor-in-possession while subject to the jurisdiction of the Bankruptcy Court.

PG&E s Consolidated Financial Statements have been prepared in accordance with the American Institute of Certified Public Accountants Statement of Position (SOP) 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code, and on a going concern basis, which contemplates continuity of operations, realization of assets and repayment of liabilities in the ordinary course of business. However, as a result of the bankruptcy of PG&E, as further discussed below, such realization of assets and liquidation of liabilities is subject to uncertainty.

Under SOP 90-7, certain liabilities of PG&E 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 PG&E s reported interest expense differs from its stated contractual interest is disclosed on the Consolidated Statements of Operations.

PG&E s Consolidated Financial Statements and Notes to the 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

PG&E provides electric service to approximately 4.8 million electric distribution customers and natural gas service to approximately 3.9 million customers in Northern and Central California. Effective January 1, 1997, PG&E Corporation became the holding company of PG&E and its subsidiaries.

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 Financial 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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

found within a company. FIN 46 provides some general guidance as to the definition of a variable interest entity. PG&E 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 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 is currently evaluating the impacts of FIN 46 s initial recognition, measurement, and disclosure provisions on its Consolidated Financial Statements.

*Accounting for Stock-Based Compensation Transition and Disclosures*On December 31, 2002, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 148, Accounting for Stock-Based Compensation Transition and Disclosures, an Amendment of FASB Statement No. 123 (SFAS No. 148). 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 with SFAS No. 123, Accounting for Stock-Based Compensation (SFAS No. 123). 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. SFAS No. 148 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. SFAS No. 148 is effective upon its issuance.

PG&E 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, (APB No. 25) elected under SFAS No. 123, as amended. As a result, the adoption of SFAS No. 148 did not have any impact on the Consolidated Financial Statements of PG&E.

Please refer to the Stock-Based Compensation section of this Note 1 for additional information.

Changes to Accounting for Certain Derivatives During 2002 the FASB s Derivatives Implementation Group (DIG) issued two DIG Issues C15 and C16, which changed the definition of normal purchases and sales included in 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 (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 was not impacted by these accounting changes.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Accounting for the Impairment or Disposal of Long-Lived Assets On January 1, 2002, PG&E adopted SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets (SFAS No. 144). 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. SFAS No. 144 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 SFAS No. 144 at January 1, 2002, did not have any impact on the Consolidated Financial Statements of PG&E.

Accounting for Goodwill and Other Intangible Assets On January 1, 2002, PG&E adopted SFAS No. 142, Goodwill and Other Intangible Assets (SFAS No. 142). SFAS No. 142 eliminates the amortization of goodwill and requires that goodwill be reviewed at least annually for impairment. PG&E had no goodwill on its balance sheet at December 31, 2002, or December 31, 2001.

SFAS No. 142 also requires that the useful lives of previously recognized intangible assets be reassessed and the remaining amortization periods be adjusted accordingly. Adoption of SFAS No. 142 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.

PG&E s intangible assets other than goodwill consist of Hydro licenses and other agreements, which at December 31, 2002 had a gross carrying value of $67 million and accumulated amortization of $16 million. As at December 31, 2001 these Hydro licenses and other agreements had a gross carrying value of $66 million and accumulated amortization of $14 million.

PG&E s amortization expense of intangible assets was $3 million in 2002, $2 million in 2001, and $2 million in 2000. PG&E s estimated amortization expense for intangible assets for full years 2003 through 2007 is expected to be approximately $3 million annually.

Accounting for Asset Retirement Obligations In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143). PG&E 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 SFAS No. 143, 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 SFAS No. 143 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 estimates the impact of adopting SFAS No. 143 effective January 1, 2003, will be as follows:

PG&E will adjust its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. PG&E 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 8, Nuclear Decommissioning). PG&E has accrued, at December 31, 2002, $52 million to

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

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.

PG&E 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).

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 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 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 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, and fuel oil. Materials, supplies, and gas stored underground are valued at average cost. Fuel oil is valued using the last-in first-out method.

Income Taxes

PG&E uses 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 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 PG&E are parties to a tax-sharing arrangement under which PG&E determines its income tax provision (benefit) on a stand-alone basis.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Investment in Affiliates

PG&E has investments in unconsolidated affiliates, which are mainly engaged in the purchase of residential real estate property. The equity method of accounting is applied to PG&E s investment in these entities. Under the equity method, PG&E s share of equity income or losses of these entities is reflected as equity in earnings of affiliates. As of December 31, 2002, PG&E s recorded investment in these entities totaled $15 million. As a limited partner, PG&E s exposure to potential loss is limited to its investment in each partnership.

Related Party Agreements and Transactions

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

PG&E s significant related party transactions were as follows:

	Year Ended December 31,		
	2002	2001	2000
		(in millions)	
PG&E proceeds from:			
Administrative services provided to PG&E Corporation	$ 7	$ 6	$ 12
Gas reservation services provided to PG&E Energy Trading Holdings Corporation (PG&E ET)[1]	9	11	12
Contribution in aid of construction received from PG&E NEG	2	5	3
Other		1	2
Trade Deposit due from PG&E Gas Transmission Northwest Corporation (PG&E GTN)[1]		11	
PG&E payments for:			
Administrative services received from PG&E Corporation	$106	$127	$ 83
Interest on Debt to PG&E Corporation	8	3	3
Administrative services received from PG&E NEG	2		
Gas commodity services received from PG&E ET[1]	49	120	136
Interest on Debt to PG&E ET[1]	2		
Transmission services received from PG&E GTN[1]	47	40	46
Trade Deposit due to PG&E ET[1]	7		

(1) Subsidiaries of PG&E NEG

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Property, Plant and Equipment

Property, Plant and Equipment are reported at original cost, unless impaired under the provisions of SAFS No. 144. Original cost includes:

Labor and materials;

Construction overhead; and

Capitalized interest or an allowance for funds used during construction (AFUDC).

Capitalized Interest and 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 for PG&E amounted to $27 million for the year ended December 31, 2002 and $18 million for each year ended December 31, 2001 and 2000.

PG&E periodically evaluates 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 charged the original cost of retired plant and removal costs less salvage value to accumulated depreciation upon retirement of its plant in service that apply SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, as amended (SFAS No. 71).

Depreciation

Property, plant and equipment are depreciated on a straight-line basis over estimated useful lives, less any residual or salvage value. PG&E s composite depreciation rate was 3.42 percent for the year ended December 31, 2002, 3.63 percent for the year ended December 31, 2001, and 4.54 percent for the year ended December 31, 2000. The estimated useful lives of property, plant and equipment are as follows:

Electric generating facilities	15 to 50 years
Electric distribution facilities	16 to 63 years
Electric transmission	27 to 65 years
Gas distribution facilities	28 to 49 years
Gas transmission	25 to 45 years
Gas storage	25 to 48 years
Other	5 to 40 years

The useful lives of PG&E 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. PG&E 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.

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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Capitalized Software Costs

PG&E capitalizes costs incurred during the application development stage of internal use software projects to property, plant and equipment. Capitalized software costs totaled $33 million at December 31, 2002, and $225 million at December 31, 2001, net of accumulated amortization of $15 million at December 31, 2002, and $85 million at December 31, 2001. PG&E amortizes capitalized software costs ratably over the expected lives of the projects ranging from 7 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, Recission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13 and Technical Corrections (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 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 PG&E 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 PG&E s debt is determined using the present value of future cash flows; and

The fair values of nuclear decommissioning funds, rate reduction bonds, PG&E s preferred stock, and PG&E s 7.90 percent deferrable interest subordinated debentures are determined based on quoted market prices.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

The carrying amount and fair value of PG&E 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):

	At December 31,			
	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Nuclear decommissioning funds (Note 8):	$1,335	$1,335	$1,337	$1,337
Long-term debt (Note 3):	4,820	4,631	5,153	4,975
Rate reduction bonds (Note 4):	1,450	1,580	1,740	1,811
PG&E preferred stock with mandatory redemption provisions (Note 6):	137	132	137	109
7.90 percent cumulative quarterly income preferred securities (Note 3)			300	246
7.90 percent deferrable interest subordinated debentures (Note 3)	300	275		

Regulation and Statement of Financial Accounting Standards No. 71

PG&E accounts 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. PG&E is regulated by the CPUC, the FERC, and the Nuclear Regulatory Commission (NRC), among others.

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 PG&E s operations no longer are 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:

	Balance at December 31,	
	2002	2001
	(in millions)	
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 regulatory assets	$2,011	$2,283

Regulatory assets are charged to expense during the period that the costs are reflected in regulated revenues.

PG&E 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. PG&E s regulatory asset related to

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

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. PG&E 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, PG&E expects to recover deferred income tax-related regulatory assets over periods ranging from 1 to 39 years.

In general, PG&E does not earn a return on regulatory assets where the related costs do not accrue interest. At December 31, 2002, PG&E did not earn a return on regulatory assets related to deferred income taxes of $229 million.

Regulatory Liabilities

Regulatory liabilities comprise the following:

	Balance at December 31,	
	2002	**2001**
	(in millions)	
Employee benefit plans	$1,102	$1,133
Public purpose programs	182	218
Rate reduction bonds	102	17
Other	75	117
Total regulatory liabilities	$1,461	$1,485

PG&E 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. PG&E 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. PG&E s regulatory liability for rate reduction bonds represents the deferral of over-collected revenue associated with the rate reduction bonds that PG&E expects to return to ratepayers in the future.

Regulatory Balancing Accounts

Sales balancing accounts accumulate differences between recorded revenues and revenues PG&E is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs PG&E 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. PG&E s regulatory balancing accounts accumulate balances until they are refunded to or received from PG&E customers through authorized rate adjustments.

As a result of the California energy crisis discussed in Note 2, PG&E could no longer conclude that power-generation and procurement-related balancing accounts meet the requirements of SFAS No. 71. However, PG&E continues to record balancing accounts associated with its electricity and gas distribution and transmission businesses.

In 2002, the CPUC ordered PG&E 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 PG&E cannot conclude that the amounts in these balancing accounts are considered probable of recovery in future rates, PG&E has reserved these balances by recording a charge against earnings. As of December 31, 2002, the reserve for these balances was $136 million.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

PG&E s current regulatory balancing account assets comprise the following:

	Balance at December 31,	
	2002	2001
	(in millions)	
Gas Revenue Balancing Accounts	$ 65	$ 42
Gas Cost Balancing Accounts	33	25
Electric Distribution Cost Balancing Accounts		8
Total	$ 98	$ 75

PG&E s current regulatory balancing account liabilities comprise the following:

	Balance at December 31,	
	2002	2001
	(in millions)	
Gas Revenue Balancing Accounts	$ 4	$ 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

PG&E 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 PG&E 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.

Electric utility revenues, which are comprised of generation, transmission, and distribution services, are billed to PG&E 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. PG&E s 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 PG&E s customers to cover the amount of electricity needed by PG&E s customers that could not be met by PG&E s purchased power contracts and retained generation facilities. Under California law, the DWR is deemed to sell the electricity directly to PG&E s retail customers, not to PG&E. Therefore, PG&E 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 PG&E bills its customers, PG&E 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 PG&E s electric revenues in its Consolidated Statements of Operations.

Accounting for Price Risk Management Activities

PG&E has engaged in price risk management activities for non-trading purposes to hedge against price fluctuations of natural gas and electricity. Due to PG&E s credit rating downgrade and subsequent bankruptcy,

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

risk management activities have been limited to forward and option contracts related to PG&E s natural gas portfolio and the continuation of power forward contracts that were in existence prior to the bankruptcy.

Derivatives associated with non-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. 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 fair value are recognized in accumulate other comprehensive income (loss) until the hedges item is recognized in earnings. PG&E 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 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 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 adopted SFAS No. 133 that requires that all derivatives, as defined, are recognized on the balance sheet at fair value. PG&E 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 also has derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business. These derivatives are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception, and are not reflected on the balance sheet at fair value.

Stock-Based Compensation

PG&E accounts 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 does not recognize any compensation expense, as the exercise price of all stock options is equal to the fair market value at the time the options are granted. Had compensation expense been recognized using the fair value-based method under SFAS No. 123, PG&E s pro forma consolidated earnings (loss) and earnings (loss) would have been as follows:

	Year Ended December 31,		
	2002	**2001**	**2000**
		(in millions)	
Net earnings (loss) available for common stock:			
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)
Pro forma	$1,787	$1,008	$(3,488)

Comprehensive Income

Comprehensive income 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 s comprehensive

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

income 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.

Note 2: 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 PG&E to sell more than 50 percent of its fossil fuel-fired generation facilities and made it economically unattractive for PG&E to retain its remaining generation facilities. The new market framework called for the creation of the Power Exchange (PX) and the 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, PG&E 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 PG&E 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 PG&E s customers continued to buy electricity from PG&E.

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, PG&E s retail electric rates were frozen and provided only approximately $0.05 per kWh to pay for PG&E s electricity costs.

The frozen rates were designed to allow PG&E to recover its authorized utility costs and, to the extent the frozen rates generated revenues in excess of PG&E s authorized utility costs, recover its transitions costs. During the California energy crisis, frozen rates were insufficient to cover PG&E s electricity procurement and other costs. Because PG&E could no longer conclude that its under-collected electricity procurement and remaining transition costs were probable of recovery, PG&E charged $6.9 billion to expense for these costs at December 31, 2000. PG&E s inability to recover procurement costs from customers ultimately resulted in billions of dollars in defaulted debt and unpaid bills and caused PG&E 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. PG&E 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, PG&E did not begin collecting the revenues until June 2001. As a result, in May 2001, the CPUC authorized PG&E to collect an additional $0.005 per kWh (half-cent) 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 PG&E to continue collecting the half-cent surcharge until further consideration by the CPUC and to record the surcharge revenues in a balancing account. PG&E had recorded a regulatory liability for the $0.005 per kWh 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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

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 PG&E 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 PG&E s under-collected costs, if any, remaining at the end of the rate freeze. If the CPUC determines that PG&E recovered revenues in excess of its transition costs or in excess of other permitted uses, the CPUC may require PG&E 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. PG&E cannot predict the outcome of this case or whether the CPUC or others would attempt to apply any ruling to PG&E. If PG&E is ordered to refund material amounts to ratepayers, PG&E s financial condition and results of operations would be materially adversely affected.

In December 2002, the CPUC issued a decision authorizing PG&E 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, PG&E 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 DWR revenue requirement, PG&E 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, PG&E 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, PG&E 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 PG&E 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 PG&E s bankruptcy and future regulatory and judicial proceedings, including the outcome of PG&E 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 PG&E against the CPUC Commissioners, asking the court to declare that the federally approved wholesale electricity costs that PG&E 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 PG&E 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 PG&E and to determine the extent and disposition of PG&E 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 PG&E s bankruptcy proceeding (see below), proposing that PG&E s overall retail electric rates be maintained at current levels through January 31, 2003, in order to generate cash to repay in part PG&E 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, PG&E 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 PG&E 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 PG&E s overall retail electric rates retroactively. PG&E 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 PG&E 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 PG&E 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 PG&E s request for rehearing. PG&E is currently appealing this matter to the U.S. District Court for the Northern District of California. PG&E 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. PG&E 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. PG&E has filed comments on this matter with the CPUC. However, the CPUC has not yet issued a decision.

On January 17, 2002, PG&E filed an administrative claim with the State of California Victim Compensation and Government Claims Board (the Board) alleging that the new law violates PG&E s statutory rights under California s deregulation law AB 1890. PG&E 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 PG&E s claim. Having exhausted remedies before the Board, PG&E 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. PG&E has 60 days to file an appeal and intends to do so. PG&E 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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Electricity Purchases

In January 2001, as wholesale electric prices continued to exceed retail rates, the major credit rating agencies lowered their ratings for PG&E to non-investment grade levels. Consequently, PG&E 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 PG&E 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 PG&E s net open position, leaving the ISO to purchase the remainder in order to avoid blackouts. The ISO billed PG&E for its costs to purchase electricity to cover the amount of PG&E s net open position not covered by the DWR. In 2001, PG&E 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 PG&E 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 PG&E 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 PG&E. As such, in light of the March 2002 FERC order and the February and March 2002, CPUC decisions, in the first quarter of 2002 PG&E 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 PG&E is required to pass through to the DWR. The DWR s proposed amendment changes the calculation that determines the amount of revenues that PG&E 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 PG&E 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 PG&E must pass-through to the DWR. As a result, as of December 31, 2002, PG&E has accrued an additional $369 million (pre-tax) liability for pass-through revenues for electricity provided by the DWR to PG&E s customers.

In October 2002, PG&E 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. PG&E 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 PG&E 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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

after the CPUC allocated existing DWR contracts for electricity procurement to each California IOU, an electricity procurement plan to meet the 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 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 PG&E 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, PG&E 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 PG&E, 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 PG&E 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. PG&E s proposed plan of reorganization (Plan) (see below) prohibits PG&E 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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

authority to effect such a transfer of legal title in the future. PG&E has informed the CPUC, the DWR and the State of California that PG&E would vigorously oppose any attempt to transfer the DWR allocated contracts to PG&E without PG&E s consent.

Chapter 11 Filing

On April 6, 2001, PG&E filed for relief under Chapter 11 of the Bankruptcy Code. Under Chapter 11, PG&E is subject to the jurisdiction of the Bankruptcy Court, however PG&E has control of its assets and is authorized to operate its business as a debtor-in-possession. Subsidiaries of PG&E, including PG&E Funding, LLC (which holds rate reduction bonds) and PG&E Holdings, LLC (which holds stock of PG&E), are not included in PG&E s Chapter 11 filing. PG&E Corporation, is a co-proponent of PG&E s proposed plan of reorganization.

In connection with PG&E 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 PG&E 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.

PG&E 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 PG&E objections. PG&E 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. PG&E 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, PG&E has accrued interest on all claims PG&E 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 PG&E s Liabilities Subject to Compromise from the period of December 31, 2001 to December 31, 2002.

	(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 PG&E Subordinated Debentures (Note 3)	0.3
Reversal of first quarter 2001 ISO accrual	(1.0)
Liabilities Subject to Compromise at December 31, 2002	$ 9.4

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 PG&E 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 PG&E to pay all undisputed creditor

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

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, PG&E has paid approximately $1.3 billion through January 2, 2003, for pre- and post-petition interest on certain undisputed claims. PG&E 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, PG&E 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 PG&E 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 PG&E is paying interest on these other claims at the various rates as described below. For certain claims, PG&E has identified receivable balances owed to PG&E 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 PG&E s proposed plan of reorganization described below, PG&E 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	Agreed Upon Rate	
	(in millions)	(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	
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, PG&E has recorded interest at the contractual or FERC-tariffed interest rate. When those rates do not apply, PG&E has recorded interest at the federal judgment rate.

PG&E 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, PG&E 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 PG&E to continue its normal business operations while operating as a debtor-in-possession. For example, PG&E 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, PG&E is authorized to refund certain

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

customer deposits, use certain bank accounts and cash collateral, and assume responsibility for various hydroelectric contracts.

Proposed Plan of Reorganization

PG&E and PG&E Corporation have jointly proposed a plan of reorganization (the Plan), which would allow PG&E to restructure its businesses and refinance the restructured businesses. The Plan is designed to align PG&E 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 NRC. After this realignment, the retail-focused business would be a natural gas and electricity distribution company (Reorganized PG&E), representing approximately 70 percent of the book value of PG&E s assets.

In contemplation of the Plan becoming effective, PG&E has created three new limited liability companies (the LLCs) which currently are owned by PG&E s wholly owned subsidiary, Newco Energy Corporation (Newco). On the effective date of the Plan, PG&E would transfer substantially all the assets and liabilities primarily related to PG&E s electricity generation business to Electric Generation LLC (Gen); the assets and liabilities primarily related to PG&E s electricity transmission business to ETrans LLC (ETrans); and the assets and liabilities primarily related to PG&E s natural gas transportation and storage business to GTrans LLC (or GTrans).

The Plan proposes that on the effective date, PG&E 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 PG&E s common stock that it then holds to its existing shareholders in a spin-off transaction. After the spin-off, the Reorganized PG&E would be an independent publicly held company. The common stock of the Reorganized PG&E 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 PG&E would apply to list its common stock on the New York Stock Exchange. The Reorganized PG&E would retain the name Pacific Gas and Electric Company.

Although the Reorganized PG&E would be legally separated from the LLCs, the Reorganized PG&E s operations would remain connected to the operations of the LLCs after the effective date of the Plan. For example:

The Reorganized PG&E would rely on Gen for a significant portion of the electricity the Reorganized PG&E needs to meet its electricity distribution customers demand during the 12-year term of a power purchase and sale agreement between the Reorganized PG&E and Gen, or the Gen power purchase and sale agreement.

The Reorganized PG&E would rely on ETrans for the Reorganized PG&E s electricity transmission needs because the transmission lines proposed to be transferred to ETrans are currently the only transmission lines directly connected to PG&E s electricity distribution system.

The Reorganized PG&E would rely on GTrans for the Reorganized PG&E s natural gas transportation needs because the facilities proposed to be transferred to GTrans are currently the only transportation facilities directly connected to PG&E s natural gas distribution system. In addition, the Reorganized PG&E would rely on GTrans for a substantial portion of the Reorganized PG&E s natural gas storage requirements for at least 10 years under a transportation and storage services agreement between the Reorganized PG&E and GTrans, though PG&E does have storage options with third party providers to meet a portion of their requirements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

The Reorganized PG&E also would have significant operating relationships with the LLCs covering a range of functions and services.

Finally, the Reorganized PG&E would continue to rely on its natural gas transportation agreement with PG&E GTN, for the transportation of western Canadian natural gas.

During 2002, PG&E undertook several initiatives to prepare for separation under the Plan. PG&E 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 PG&E and the Reorganized PG&E would then transfer the notes to certain holders of allowed claims. In addition, each of the Reorganized PG&E, 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 PG&E 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 PG&E and the LLCs in connection with the implementation of the 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 PG&E 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, PG&E filed amendments to the PG&E Plan with the Bankruptcy Court that, among other modifications:

Permit the Reorganized PG&E and the LLCs to issue secured debt instead of unsecured debt,

Permit adjustments in the amount of debt the Reorganized PG&E 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 PG&E s mortgage-backed pollution control bonds to be redeemed if the Reorganized PG&E issues secured new money notes, and

Commit PG&E Corporation to contribute up to $700 million in cash to PG&E s capital from the issuance of equity or from other available sources, to the extent necessary to satisfy the cash obligations of PG&E 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 PG&E 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;

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

PG&E Corporation and PG&E shall have received all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions, or documents that are determined by PG&E Corporation and PG&E to be necessary to implement the Plan;

S&P and Moody s Investor Services Inc. (Moody s) shall have established investment-grade credit ratings for each of the securities to be issued by the Reorganized PG&E, 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 PG&E 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. PG&E s obligations with respect to claims and equity interests would remain unchanged.

PG&E Corporation and PG&E 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 PG&E 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 PG&E that does not call for realignment of PG&E s existing businesses (the CPUC/OCC Plan). The alternative plan instead provides for the continued regulation of all of PG&E 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 PG&E and the CPUC enter into a reorganization agreement under which the CPUC promises to establish retail electric rates on an ongoing basis sufficient for PG&E 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 PG&E 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 believes the alternative plan is not credible or confirmable. PG&E does not believe the alternative plan would restore PG&E to investment grade status if the alternative plan were to become effective. Additionally, PG&E believes the alternative plan would violate applicable federal and state law.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

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 PG&E 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 PG&E 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.

PG&E 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 PG&E s future liquidity and results of operations. PG&E is unable at this time to predict the outcome of its bankruptcy case or the effect of the reorganization process on the claims of PG&E s creditors or the interests of PG&E s preferred shareholders. However, PG&E 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: Long-Term Debt

Long-term debt that matures in one year or more from the date of issuance consisted of the following:

	Balance at December 31,	
	2002	**2001**
	(in millions)	
First and refunding mortgage bonds:		
Maturity Interest Rates		
2003-2005 5.875% to 6.250%	$ 880	$1,214
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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

	Balance at December 31,	
	2002	2001
	(in millions)	
Long-Term Debt Subject to Compromise:		
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 PG&E long-term debt	19	20
Total Long-Term Debt Subject to Compromise	$2,100	$1,801

First and Refunding Mortgage Bonds First and refunding mortgage bonds are issued in series and bear annual interest rates ranging from 5.85 percent to 8.80 percent. All real properties and substantially all personal properties of PG&E are subject to the lien of the mortgage, and PG&E is required to make semi-annual sinking fund payments for the retirement of the bonds. While in bankruptcy, PG&E is prohibited from making payments on the Mortgage Bonds, without permission from the Bankruptcy Court. The Bankruptcy Court approved the payment of $333 million of mortgage bonds maturing in March 2002 and has also approved the payment of interest in accordance with the terms of the bonds.

Included in the total mortgage bonds outstanding at December 31, 2002, and 2001, were $345 million of bonds held in trust for the California Pollution Control Financing Authority (CPCFA) with interest rates ranging from 5.85 percent to 6.63 percent and maturity dates ranging from 2009 to 2023. In addition to these bonds, PG&E holds long-term pollution control loan agreements with the CPCFA as described below.

Senior Notes In November 2000, PG&E issued $680 million of five-year senior notes with an interest rate of 7.38 percent. PG&E used the net proceeds to repay short-term borrowings incurred to finance scheduled payments due to the PX for August 2000 power purchases and for other general corporate purposes. These notes contained interest rate adjustments dependent upon PG&E s unsecured debt ratings.

As a result of PG&E s credit rating downgrades, there was an interest rate adjustment of 1.75 percent on the $680 million senior notes. In addition, there was an interest premium penalty of 0.5 percent imposed on the senior notes due to PG&E s inability to make a public offering on April 30, 2001. Accordingly, the rate increased to 9.63 percent from 7.38 percent effective November 1, 2001. In 2001, PG&E s bankruptcy filing and failure to make payments on the senior notes were events of default. The senior notes have been classified as Liabilities Subject to Compromise in the Consolidated Balance Sheets at December 31, 2002, and 2001.

Pollution Control Loan Agreements Pollution control loan agreements from the CPCFA totaled $814 million at December 31, 2002, and 2001.

Interest rates on $614 million of the loans are variable. For 2002, the variable interest rates ranged from 1.25 percent to 1.78 percent. These loans are subject to redemption by the holder under certain circumstances. They were secured primarily by irrevocable letters of credit (LOC) from certain banks, which based on terms negotiated in 2002, mature in 2003 through 2004. On March 1, 2001, a $200 million loan was converted to a fixed rate obligation with an interest rate of 5.35 percent.

In April and May 2001, four loans totaling $454 million were accelerated and the banks paid the amounts due under the LOCs. In the meantime, PG&E was unable to make interest payments due to the bankruptcy filing.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

This resulted in like obligations from PG&E to the banks. Amounts outstanding at December 31, 2002, and 2001, under the pollution control agreements were classified as Liabilities Subject to Compromise in the Consolidated Balance Sheets at December 31, 2002 and 2001.

Medium-Term Notes PG&E has outstanding $287 million of medium-term notes due from 2002 to 2014 with interest rates ranging from 5.81 percent to 8.45 percent, which are also in default. The outstanding principal amounts at December 31, 2002, and 2001, were classified as Liabilities Subject to Compromise in the accompanying financial statements.

7.90 Percent Deferrable Interest Subordinate Debentures

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

On March 16, 2001, PG&E postponed quarterly interest payments on the QUIDS until further notice in accordance with the bond s terms. The corresponding quarterly payments on the QUIPS, due on April 2, 2001, were similarly postponed.

Quarterly interest payments may be postponed up to 20 consecutive quarters under the terms of the bond agreement. According to the bond s terms, investors earn interest on the unpaid distributions at the rate of 7.90 percent. Upon liquidation or dissolution of PG&E, holders of the QUIPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid interest thereon to the date of payment.

As discussed in Note 2, on March 27, 2002, the Bankruptcy Court issued an order authorizing PG&E to pay pre-and post-petition interest to holders of certain undisputed claims, including QUIPS, within ten business days after Bankruptcy Court approval of PG&E s disclosure statement.

The disclosure statement was approved on April 24, 2002. On May 6, 2002, PG&E made payments to holders of QUIPS representing interest accrued through February 28, 2002, and on March 31, 2002, PG&E made an additional interest payment for the one month ended March 31, 2002. On July 1, 2002, PG&E made an interest payment for the three months ended June 30, 2002, and since then has continued to make quarterly interest payments as scheduled.

On April 12, 2001, Bank One, N.A., as successor-in-interest to The First National Bank of Chicago (Property Trustee), gave notice that an event of default exists due to PG&E s filing for Chapter 11 on April 6, 2001 (see Note 2). As a result of the event of default, the Trust was required to be liquidated by the trustee by distributing the QUIDS, after satisfaction of liabilities to creditors of the Trust, to the holders of QUIPS. Pursuant to the Property Trustee s notice dated April 24, 2002, the Trust was liquidated on May 24, 2002. Upon liquidation of the Trust, the former holders of QUIPS received a like amount of QUIDS. The terms and interest payments of the QUIDS correspond to the terms and interest payments of the QUIPS.

The QUIDS are included in financing debt classified as Liabilities Subject to Compromise on PG&E s Consolidated Balance Sheets at December 31, 2002. The QUIPS are reflected as Mandatory Redeemable Preferred Securities of Trust Holding Solely PG&E Subordinated Debentures on PG&E s Consolidated Balance Sheets at December 31, 2001.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Repayment Schedule

At December 31, 2002, PG&E s aggregate amounts of maturing long-term debt are reflected in the table below:

	Expected maturity date						
	2003	2004	2005	2006	2007	Thereafter	Total
	(dollars in millions)						
Long-term debt:							
Liabilities not subject to compromise:							
Fixed rate obligations	$ 281	$ 310	$ 290	$	$	$2,139	$3,020
Average interest rate	6.25%	6.25%	5.88%			7.25%	6.92%
Liabilities subject to compromise:							
Fixed rate obligations[1]	173	54	696	1	1	261	1,186
Average interest rate	7.40%	7.51%	9.56%	9.45%	9.45%	5.95%	8.35%
7.90 Percent Deferrable Interest Subordinated Debentures						300	300
Variable rate obligations[2]	349	265					614
Rate reductions bonds	290	290	290	290	290		1,450
Average interest rate	6.36%	6.42%	6.42%	6.44%	6.48%	%	6.42%
Total	$1,093	$ 919	$1,276	$ 291	$ 291	$2,700	$6,570

(1) $132 million out of the 2003 repayment amount matured in 2002 and 2001, and was unpaid.

(2) The expected maturity dates for pollution control loan agreements with variable interest rates are based on the maturity dates of the letters of credit securing the loans.

Credit Facilities and Short-Term Borrowings

The following table summarizes PG&E s lines of credit:

	December 31,	
	2002	2001
	(in millions)	
Credit Facilities Subject to Compromise:		
5-year Revolving Credit Facility	$ 938	$ 938
Total Lines of Credit Subject to Compromise	938	938
Short-Term Borrowings Subject to Compromise:		
Bank Borrowings Letters of Credit for Accelerated Pollution Control Agreements	454	454
Floating Rate Notes	1,240	1,240
Commercial Paper	873	873
Total Short-Term Borrowings Subject to Compromise	2,567	2,567
Total Credit Facilities and Short-Term Borrowings Subject to Compromise	$3,505	$3,505

The total amount outstanding on PG&E s credit facilities was $938 million at December 31, 2002, and 2001. The total amount outstanding on PG&E s short-term borrowings was $2,567 million at December 31, 2002, and 2001. Due to PG&E s bankruptcy filing (see Note 2), both have been classified as Liabilities Subject to Compromise in the table above and on the Consolidated Balance Sheets for 2002 and 2001.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

The weighted average interest rate on the short-term borrowings subject to compromise as of December 31, 2002 was 7.47 percent, and 7.53 percent as of December 31, 2001.

Credit Facilities At December 31, 2002, and 2001, PG&E had $938 million outstanding on a $1 billion five-year revolving credit facility. This facility was used to support PG&E s commercial paper program and other liquidity requirements. Non-payment of matured commercial paper in excess of $100 million in 2001 constituted an event of default under the credit facility and consequently the bank terminated its outstanding commitment. The outstanding balance is classified as Liabilities Subject to Compromise on the December 31, 2002, and 2001, Consolidated Balance Sheets.

Commercial Paper The total amount of commercial paper outstanding at December 31, 2002, and 2001, was $873 million. PG&E has been in default on its commercial paper obligations since January 17, 2001. The weighted average interest rate on PG&E s commercial paper obligation as of December 31, 2002, and 2001, was 7.47 percent.

Floating Rate Notes PG&E issued a total of $1,240 million of 364-day floating rate notes in November 2000, with interest payable quarterly. These notes were not paid on the maturity date of November 30, 2001. Non-payment of the floating rate notes was an event of default, entitling the floating rate note trustee to accelerate the repayment of these notes. However, PG&E is prohibited from paying liabilities incurred prior to its bankruptcy filing without Bankruptcy Court approval.

*Bank Borrowing Letters of Credit for Accelerated Pollution Control Bonds*As previously discussed in April and May 2001, four pollution control loan agreements totaling $454 million were accelerated by the note holders. These accelerations were funded by various banks under letter of credit agreements resulting in similar obligations from PG&E to the banks.

Note 4: Rate Reduction Bonds

In December 1997, PG&E Funding LLC (Funding), a limited liability corporation wholly owned by and consolidated with PG&E, issued $2.9 billion of rate reduction bonds. The proceeds of the rate reduction bonds were used by Funding to purchase from PG&E the right, known as transition property, to be paid a specified amount from a non-bypassable charge levied on residential and small commercial customers (Fixed Transition Amount (FTA) charges). FTA charges are authorized by the CPUC pursuant to state legislation and will be paid by residential and small commercial customers until the rate reduction bonds are fully retired. FTA charges are collected by PG&E and remitted to Funding based on a transition property servicing agreement. On January 4, 2001, S&P lowered PG&E s short-term credit rating to A-3, and on January 5, 2001, Moody s lowered PG&E s short-term credit rating to P-3. As a result, on January 8, 2001, PG&E was required under the transition property servicing agreement to begin remitting to Funding on a daily basis FTA charges paid by ratepayers, as opposed to once a month, as had previously been required.

The rate reduction bonds have maturity dates ranging from 2003 to 2007, and bear interest at rates ranging from 6.36 percent to 6.48 percent. The bonds are secured solely by the transition property and there is no recourse to PG&E.

The total amount of rate reduction bonds principal outstanding was $1,450 million at December 31, 2002, and $1,740 million at December 31, 2001. The scheduled principal payments on the rate reduction bonds for the years 2003 through 2007 are $290 million for each year. While Funding is a wholly owned consolidated subsidiary of PG&E, Funding is legally separate from PG&E. The assets of Funding are not available to creditors of PG&E, and the transition property is not legally an asset of PG&E.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Note 5: Common Stock

PG&E is authorized to issue 800 million shares of its $5 par value common stock. Of the total shares authorized, 321 million shares were issued and outstanding as of December 31, 2002, and 2001. PG&E Corporation and PG&E Holdings LLC, a subsidiary of PG&E, hold all of PG&E s outstanding common stock.

PG&E did not repurchase any shares of its common stock during the years ended December 31, 2002, and 2001. In April 2000, PG&E Holdings LLC repurchased 11.9 million shares of PG&E s common stock at a cost of $275 million. At December 31, 2002, and 2001, PG&E Holdings LLC held repurchased common stock totaling 19.5 million shares, at a cost of $475 million. The repurchased common stock is included as a reduction of shareholders equity on PG&E s Consolidated Balance Sheets.

In October 2000, PG&E declared a $110 million common stock dividend to PG&E Corporation and PG&E Holdings LLC. In January 2001, PG&E suspended payment of the declared dividend. The suspension was made so that PG&E could maintain its CPUC-authorized capital structure, which is the level of common and preferred equity PG&E may maintain in relation to its debt.

PG&E did not declare or pay common and preferred stock dividends in 2001 and 2002. Preferred stock dividends have a cumulative feature in which any preferred stock dividends not paid in any year must be made up in a later year before any dividends can be distributed to common shareholders. As a result, PG&E may not pay any dividends on its common stock until the cumulative preferred stock dividends and mandatory preferred sinking fund requirements are paid.

PG&E s common stock has been pledged as first priority security under the terms of PG&E Corporation s Second Amended and Restated Credit Agreement.

Note 6: Preferred Stock

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

At December 31, 2002, and 2001, PG&E had issued and outstanding 5,784,825 shares of non-redeemable preferred stock. Holders of PG&E s non-redeemable preferred stock 5.0 percent, 5.5 percent, and 6.0 percent series have rights to annual dividends per share ranging from $1.25 to $1.50.

At December 31, 2002, and 2001, PG&E had issued and outstanding 5,973,456 shares of redeemable preferred stock. PG&E s redeemable preferred stock is subject to redemption at PG&E s option, in whole or in part, if PG&E pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2002, annual dividends ranged from $1.09 to $1.76 and redemption prices ranged from $25.75 to $27.25.

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

The redemption requirements for PG&E s redeemable preferred stock with mandatory redemption provisions are for the 6.57 percent series $4 million per year from 2002 through 2006, and $55 million in 2007, and for the 6.30 percent series, $3 million per year from 2004 through 2008, and $47 million in 2009.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Due to the California energy crisis, PG&E s Board of Directors did not declare the following regular preferred stock dividends normally payable 15 days after the three-month periods ended:

January 31, 2001;

April 30, 2001;

July 31, 2001;

October 31, 2001;

January 31, 2002;

April 30, 2002;

July 31, 2002;

October 31, 2002; and

January 31, 2003.

Dividends on all PG&E preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Accumulated and unpaid preferred stock dividends amounted to $50 million as of December 31, 2002, and $25 million as of December 31, 2001. Upon liquidation or dissolution of PG&E, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. Until cumulative dividends on its preferred stock and mandatory preferred sinking fund payments are paid, PG&E may not pay any dividends on its common stock, nor may PG&E repurchase any of its common stock. A sinking fund sets aside funds for the future periodic retirement of the outstanding stocks.

Note 7: Price Risk Management

PG&E did not have any cash flow hedges at December 31, 2002, or December 31, 2001. PG&E s ineffective portion of changes in amounts of cash flow hedges was immaterial for the year ended December 31, 2001.

The schedule below summarizes the activities affecting Accumulated Other Comprehensive Income (Loss), net of tax, from derivative instruments:

	Year Ended December 31,	
	2002	2001
	(in millions)	
Derivative gains included in accumulated other comprehensive income at beginning of period	$	$
Cumulative effect of adoption of SFAS No. 133		90
Net gain (loss) from current period hedging transactions and price changes		(5)
Net reclassification to earnings		(85)
Derivative gains (losses) included in accumulated other comprehensive income at end of period		

Foreign currency translation adjustment		(2)
Other		
Accumulated other comprehensive income (loss) at end of period	$	$ (2)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Credit Risk

Credit risk is the risk of loss that PG&E 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; PRM assets; and Assets held for sale on the balance sheet). PG&E conducts 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 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 manages its credit risk in accordance with its respective Risk Management Policies. The policies establish processes for assigning credit limits to counterparties before entering into agreements with significant exposure to PG&E. 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 takes immediate action to reduce the exposure, or obtain additional collateral, or both. Further, PG&E relies 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 calculates 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 s credit risk increased due in part to downgrades of some counterparties credit ratings to levels below investment grade. The downgrades increase PG&E 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 may face a greater potential maximum loss. In contrast, PG&E did 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 has recognized no losses due to the contract defaults or bankruptcies of counterparties. However, in 2001, PG&E terminated its contracts with a bankrupt company, which resulted in a pre-tax charge to earnings of $60 million after application of collateral held and accounts payable.

At December 31, 2002, PG&E had one investment-grade counterparty that represented 21 percent of PG&E s net credit exposure, and one below investment-grade counterparty that represented 11 percent of PG&E s net credit exposure. Investment grade is determined using publicly available information, i.e. rated at least Baa3 by Moody s and BBB- by S&P. At December 31, 2001, PG&E had no single counterparty that represented greater than 10 percent of PG&E s net credit exposure.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

The schedule below summarizes PG&E 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 s credit risk exposure to counterparties with a greater than 10 percent net credit exposure, at December 31, 2002, and December 31, 2001:

	Gross Credit Exposure Before Credit Collateral[(1)]	Credit Collateral[(2)]	Net Credit Exposure[(2)]	Number of Counterparties >10%	Net Exposure of Counterparties >10%
			(in millions)		
At December 31, 2002[(3)]	$288	$113	$175	2	$ 55
At December 31, 2001[(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) PG&E s gross credit exposure includes wholesale activity only. Retail activity and payables incurred prior to PG&E s bankruptcy filing are not included. Retail activity at PG&E 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 $64 million, or 37 percent of PG&E 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 PG&E s net credit exposure, was to entities that had credit ratings below investment grade. 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.

PG&E s concentration of credit risk reflects 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. PG&E has a net regional concentration of credit exposure totaling $175 million to counterparties that conduct business primarily throughout North America.

Note 8: Nuclear Decommissioning

Decommissioning of PG&E s nuclear power facilities is scheduled to begin, for ratemaking purposes, 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 at Diablo Canyon Power Plant (Diablo Canyon) and Humboldt Bay Power Plant (Humboldt Bay) is $1.9 billion in 2002 dollars (or $8.4 billion in future dollars). This estimate is (1) based on a February 2002 decommissioning cost study, and (2) includes labor, materials, waste disposal and other costs. PG&E plans to fund these costs from independent decommissioning trusts, which receive annual contributions as discussed further below. PG&E estimates after-tax annual earnings, including realized gains and losses, on the tax-qualified decommissioning funds of 6.34 percent and non-tax-qualified decommissioning funds of 5.39 percent. The decommissioning cost estimates are based on the plant location and cost characteristics for PG&E s nuclear plants. Actual decommissioning costs are expected to vary from this estimate because of changes in assumed dates of decommissioning, regulatory requirements,

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

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 and is included in accumulated depreciation and decommissioning on PG&E s Consolidated Balance Sheets.

On January 1, 2003, PG&E adopted SFAS No. 143. Under SFAS No. 143, PG&E will adjust its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. See Note 1 under Adoption of New Accounting Policies Accounting for Asset Retirement Obligations.

On March 15, 2002, PG&E filed its 2002 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP), seeking to increase its nuclear decommissioning revenue requirements for the years 2003 through 2005 based on the February 2002 cost study. PG&E s NDCTP 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 NDCTP also seeks recovery of $7.3 million in CPUC-jurisdictional revenue requirements for Humboldt Bay operating and maintenance costs. These costs include the radiation protection, surveillance activities, security forces, and maintenance of security systems. PG&E 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 balancing account would require PG&E to return to ratepayers any amounts collected as part of PG&E s nuclear decommissioning revenue requirement that were not contributed to the independent trusts.

Until post-rate freeze ratemaking is implemented, an increase in PG&E s nuclear decommissioning revenue requirements would reduce the amount of revenues available to offset electric generation costs, and would not have an impact on PG&E s results of operations.

The CPUC held hearings on the NDCTP in September 2002 and is scheduled to issue a final decision in April 2003.

For the year ended December 31, 2002, and December 31, 2001, annual nuclear decommissioning trust contributions collected in rates were $24 million and this amount was contributed to the trusts.

Amounts contributed to the funds, along with accumulated earnings, will be used exclusively for decommissioning and cannot be released from the trusts until authorized by the CPUC. Trust fund earnings increase the trust fund balance and the accumulated provision for decommissioning.

The CPUC has authorized the qualified trust to invest a maximum of 50 percent of its funds in publicly traded equity securities, of which up to 20 percent may be invested in publicly traded non-US securities. For the nonqualified trust, no more than 60 percent may be invested in publicly traded equities. The trusts are in compliance with the investment restrictions authorized by the CPUC.

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

The following table provides a summary of the amortized cost and fair value, based on quoted market prices, of PG&E s nuclear decommissioning trust funds:

	Maturity Date	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
			(in millions)		
Year ended December 31, 2002					
U.S. government and agency issues	2003-2032	$ 423	$ 50	$	$ 473
Municipal bonds and other	2003-2034	185	12	(1)	196
Equity securities		394	281	(9)	666
Total		$1,002	$343	$(10)	$1,335
Other assets					89
Other liabilities					(89)
Fair Value					$1,335
Year ended December 31, 2001					
U.S. government and agency issues	2002-2031	$ 437	$ 39	$	$ 476
Municipal bonds and other	2002-2034	218	14	(1)	231
Equity securities		371	347	(12)	706
Total		$1,026	$400	$(13)	$1,413
Other assets					44
Other liabilities					(120)
Fair Value					$1,337

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

	Year Ended December 31,		
	2002	2001	2000
		(in millions)	
Proceeds received from sales of securities	$1,631	$751	$1,379
Gross realized gains on sales of securities held as available-for-sale	51	71	74
Gross realized losses on sales of securities held as available-for-sale	91	98	64

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE), is responsible for the permanent storage and disposal of spent nuclear fuel.

PG&E has signed a contract with the DOE to provide for the disposal of spent nuclear fuel and high-level radioactive waste from PG&E s nuclear power facilities. The DOE s current estimate for an available site to begin accepting physical possession of the spent nuclear fuel is 2010.

At the projected level of operation for Diablo Canyon, PG&E s facilities are able to store on-site all spent fuel produced through approximately 2007. It is likely that an interim or permanent DOE storage facility will not be available for Diablo Canyon s spent fuel by 2007. Therefore, PG&E is examining its options for providing additional temporary spent fuel storage at Diablo Canyon or other facilities.

Note 9: Employee Benefit Plans

PG&E provides both qualified and nonqualified noncontributory defined benefit pension plans for its employees, retirees, and non-employee directors (referred to collectively as pension benefits). PG&E also

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

provides 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). The following schedules aggregate all of PG&E s plans.

The following schedule reconciles the plans funded status to the prepaid or accrued benefit cost recorded on the Consolidated Balance Sheets. The plans funded status is the difference between the fair value of plan assets and the benefit obligations.

	Pension Benefits		Other Benefits	
	2002	2001	2002	2001
	(in millions)			
Change in benefit obligation				
Benefit obligation at January 1	$(6,047)	$(5,369)	$(1,046)	$ (994)
Service cost for benefits earned	(139)	(127)	(24)	(21)
Interest cost	(435)	(417)	(76)	(73)
Actuarial loss	(408)	(405)		
Participants paid benefits			(99)	(10)
Settlement	1		(25)	(19)
Benefits and expenses paid	296	271	73	71
Benefit obligation at December 31	$(6,732)	$(6,047)	$(1,197)	$(1,046)
Change in plan assets				
Fair value of plan assets at January 1	$ 7,132	$ 7,761	$ 899	$ 997
Actual return on plan assets	(686)	(362)	(146)	(69)
Company contributions	10	4	47	25
Plan participant contribution			25	19
Settlement	(8)			
Benefits and expenses paid	(296)	(271)	(76)	(73)
Fair value of plan assets at December 31	$ 6,152	$ 7,132	$ 749	$ 899
Funded Status				
Plan assets greater (lower) than benefit obligation	$ (579)	$ 1,085	$ (447)	$ (147)
Unrecognized prior service cost	312	357	12	14
Unrecognized net (gain) loss	1,196	(494)	174	(156)
Unrecognized net transition obligation	22	36	257	283
Prepaid (accrued) benefit cost	$ 951	$ 984	$ (4)	$ (6)

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Net benefit income (cost) was as follows:

	Pension Benefits December 31,			Other Benefits December 31,		
	2002	2001	2000	2002	2001	2000
	(in millions)					
Service cost for benefits earned	$(139)	$(127)	$(118)	$(24)	$(21)	$(16)
Interest cost	(435)	(417)	(384)	(76)	(73)	(71)
Expected return on assets	593	641	675	75	82	89
Amortized prior service and transition cost	(59)	(55)	(55)	(28)	(28)	(28)
Amortization of unrecognized gain	5	82	182	4	21	32
Settlement (loss) gain	(7)					
Benefit income (cost)	$ (42)	$ 124	$ 300	$(49)	$(19)	$ 6

Net benefit income (cost) was calculated using expected return on plan assets of 8.5 percent for both pension and other benefits.

The difference between actual and expected return on plan assets is included in net amortization and deferral and is considered in the determination of future net benefit income (cost). The actual return on plan assets was below the expected return in 2002, 2001, and 2000.

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

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

	Pension Benefits December 31,			Other Benefits December 31,		
	2002	2001	2000	2002	2001	2000
Discount rate	6.75%	7.25%	7.50%	6.75%	7.25%	7.50%
Average rate of future compensation increases	5.00	5.00	5.00	5.00	5.00	5.00
Expected return on plan assets	8.10	8.50	8.50	(1)	8.50	8.50

(1) As of the end of 2002, PG&E changed the expected long-term rate of return on plan assets for various funded plans as follows:

Other Benefits:		
Defined Benefit	Medical Plan Bargaining	8.50%
Defined Benefit	Medical Plan Management	7.20%
Defined Benefit	Life Insurance Plan	8.10%

The assumed health care cost trend rate for 2003 is approximately 10.5 percent, grading down to an ultimate rate in 2008 and beyond of approximately 5.5 percent. The assumed health care cost trend rate can have a

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

significant effect on the amounts reported for health care plans. A one-percentage point change would have the following effects:

	1-Percentage Point Increase	1-Percentage Point Decrease
	(in millions)	
Effect on total service and interest cost components	$ 8	$ (7)
Effect on post retirement benefits obligation	68	(64)

Defined Contribution 401(k) Benefits

PG&E Corporation sponsors defined contribution pension plans more commonly referred to as 401(k) plans in which PG&E employees participate. These plans are qualified under applicable sections of the Internal Revenue Code. These plans provide for tax-deferred salary deductions and after-tax employee contributions as well as employer contributions. Employees designate the funds in which their contributions and any employer contributions are invested. Employer contributions include matching and/or basic contributions. For certain plans, matching employer contributions are automatically invested in PG&E Corporation common stock. Employees may reallocate matching employer contributions and accumulated earnings thereon to another investment fund or funds available to their plan at any time once they have been credited to their account. Employee contribution expense reflected in the accompanying PG&E s Consolidated Statements of Operations amounted to:

Year Ended December 31,	Amounts
	(in millions)
2002	$ 38
2001	35
2000	45

Long-Term Incentive Program

PG&E Corporation maintains a Long-Term Incentive Program (Program) that permits various stock-based incentive awards to be granted to non-employee directors, executive officers, and other employees of PG&E. The Stock Option Plan, the Performance Unit Plan, and the Non-Employee Director Stock Incentive Plan (each of which is a component of the Program) provide incentives based on PG&E Corporation s financial performance over time.

Stock Option Plan

The Stock Option Plan (SOP) provides for grants of stock options to purchase PG&E Corporation common stock to eligible participants with or without associated stock appreciation rights and dividend equivalents.

At December 31, 2002, 45,527,595 shares of PG&E Corporation common stock had been authorized for award under the SOP, with 14,507,614 shares still available under the SOP.

Fair values of options granted to PG&E employees to purchase PG&E Corporation common stock in 2002, 2001, and 2000 under the Black-Scholes valuation method, are as follows:

(1) No options were granted in 2002;

(2) Options granted in 2001 were measured using two sets of assumptions deriving weighted average fair values of $6.01 per share for 2,057,500 options granted and $5.80 per share for 2,054,100 options granted at their respective date of grant; and

(3) Options granted in 2000 had weighted average fair values at their date of grant of $3.26.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Significant assumptions used in the Black-Scholes valuation method for options granted in 2002, 2001 (two sets of assumptions), and 2000 were:

	2002	2001	2000
Expected stock price volatility	30.0%	33.00% & 29.05%	20.19%
Expected dividend yield	0%	0% & 4.35%	5.18%
Risk-free interest rate	4.65%	5.24% & 5.95%	6.10%
Expected life	10 years	10 years	10 years

In general, outstanding stock options become exercisable on a cumulative basis at one-third each year commencing two years from the date of grant and expire ten years and one day after the date of grant.

Options outstanding at December 31, 2002, had option prices ranging from $12.63 to $34.25, and a weighted average remaining contractual life of 7.4 years.

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

	2002		2001		2000	
	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
			(shares in millions)			
Outstanding, beginning of year	12.7	$22.40	8.9	$26.31	6.8	$29.25
Granted during year			4.1	14.32	3.3	19.89
Exercised during year	(0.2)	23.60	(0.1)	31.96	(0.8)	24.81
Cancellations during year	(0.1)	23.73	(0.2)	24.44	(0.4)	26.95
Outstanding, end of year	12.4	22.37	12.7	22.40	8.9	26.31
Exercisable, end of year	5.9	27.74	4.0	28.81	4.0	28.98

The following summarizes information for options outstanding and exercisable at December 31, 2002. Of the outstanding options at December 31, 2002:

(1) 4,045,600 options, related to 2001 grants had exercise prices ranging from $12.63 to $16.01, with a weighted average remaining contractual life of 9.3 years, of which 60,800 options were exercisable at a weighted average exercise price of $13.57; and

(2) 2,921,124 options, related to 2000 grants, had exercise prices ranging from $19.81 to $26.31, with a weighted average remaining contractual life of 8.0 years, of which 1,009,499 options were exercisable at a weighted average exercise price of $19.90.

In addition, 2,029,725 options were granted on January 2, 2003, at an exercise price of $14.61, the then-current market price of PG&E Corporation common stock.

Performance Unit Plan

Under the Performance Unit Plan (PUP), PG&E Corporation grants performance units to certain officers of PG&E Corporation and its subsidiaries, including PG&E. The performance units vest one-third in each of the three years following the year of grant. The number of performance units granted and the amount of compensation expense recognized in connection with the issuance of performance units during the years ended December 31, 2002, 2001, and 2000, were not material.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

PG&E Corporation Supplemental Retirement Savings Plan

The PG&E Corporation Supplemental Retirement Savings Plan (SRSP) provides supplemental retirement alternatives to eligible senior officers and key employees of PG&E Corporation and its subsidiaries, including PG&E, by allowing participants to defer portions of their compensation, including salaries, amounts awarded under the PUP, and other incentive awards. The SRSP also provides a means for eligible participants to receive and invest employer contribution amounts exceeding contribution limits within the various defined contribution plans sponsored by PG&E Corporation and its subsidiaries. Under the employee-elected deferral component of the SRSP, eligible employees of PG&E may defer all or part of their PUP (if eligible) and other incentive awards, and 5 to 50 percent of their monthly salary each month. Under the supplemental employer-provided retirement benefits component of the SRSP, eligible employees receive full employer matching contributions in excess of limitations set out by the Internal Revenue Code as qualified under defined contribution 401(k) plans into a non-qualified account. A separate non-qualified account is maintained for each eligible employee to hold any deferred and/or employer-contributed amounts with investment options available for the employee s designation. PG&E recognizes any gain or loss from these investments and adjusts each employee account on a quarterly basis. Expense related to deferred amounts is recognized in the period in which it is earned by the employee and accrued until paid under the terms of the plan. Employer contribution expense and expenses related to gain or loss from investments of contributed and deferred amounts recognized in connection with PG&E participant employees in the SRSP during the years ended December 31, 2001, and 2000, was not material. For the year ended December 31, 2002, the expense amounted to $1 million.

Executive Stock Ownership Program

The Executive Stock Ownership Program (ESOP) sets certain stock ownership targets of PG&E Corporation common stock for certain employees. The targets are set as a multiple of the employees base salary and vary according to the employee. To the extent an employee achieves and maintains the stock ownership targets, the employee will be entitled to receive additional common stock equivalents called Special Incentive Stock Ownership Premiums (SISOPs) to be credited to his or her SRSP account. The SISOPs vest three years after the date of grant and are subject to forfeiture if the employee fails to maintain his or her respective stock ownership target. The amount of expense related to SISOPs granted including the net of appreciation and depreciation on the stock price of PG&E Corporation common stock for the years ended December 31, 2002, 2001, and 2000, was not material.

Restricted Stock Awards

In January 2003, PG&E Corporation awarded restricted shares of PG&E Corporation common stock to certain employees of PG&E Corporation and its subsidiaries, including PG&E. The shares are granted with restrictions and are subject to forfeiture unless certain conditions are met. On January 2, 2003, 1.6 million shares of restricted stock were granted, of which 0.9 million related to PG&E employees.

The restricted shares are issued at the grant date and are held in an escrow account. The shares become available to the employees as the restrictions lapse. In general, the restrictions lapse automatically over a period of four years at the rate of 20 percent per year, restrictions as to an additional 5 percent of the shares will lapse per year if PG&E Corporation is in the top quartile of its comparator as measured by relative annual total shareholder return for years ending immediately before each annual lapse date.

Retention Programs

PG&E implemented various retention mechanisms in 2001. These mechanisms awarded identified key personnel of PG&E with lump-sum cash payments and/or units of Special Senior Executive Retention Grants.

The Special Senior Executive Retention Grants provide certain employees with phantom PG&E Corporation restricted stock units that, except in the event of a change in control, or on the employees death or disability,

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

vest no earlier than December 31, 2003. Vesting of one half of the awards is also dependent upon meeting certain performance measures.

The number of units of phantom stock granted under these mechanisms relating to PG&E key personnel totaled 744,325 units in 2001. The phantom stock units are marked-to-market based on the market price of PG&E Corporation common stock, and amortized as a charge to income over a four-year period. The expense recognized in connection with these retention mechanisms relating to PG&E key personnel, including cash payments and phantom restricted stock units totaled $5 million for the year ended December 31, 2002, and $14 million for the year ended December 31, 2001.

Note 10: Income Taxes

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

	Year Ended December 31,		
	2002	**2001**	**2000**
		(in millions)	
Current	$ 838	$ 902	$ (1,224)
Deferred	351	(267)	(891)
Tax credits, net	(11)	(39)	(39)
Income tax (benefit) expense	$ 1,178	$ 596	$ (2,154)

The following details net deferred income tax liabilities:

	Year Ended December 31,	
	2002	**2001**
	(in millions)	
Deferred income tax assets:		
Customer advances for construction	$ 318	$ 252
Unamortized investment tax credits	105	110
Reserve for damages	268	254
Environmental reserve	162	161
ISO energy purchases		353
Impairments		
Other	79	217
Total deferred income tax assets	932	1,347
Deferred income tax liabilities:		
Regulatory balancing accounts	175	369
Property related basis differences	1,778	1,665
Income tax regulatory asset	134	83
Other	325	323

Total deferred income tax liabilities	2,412	2,440
Total net deferred income taxes liabilities	1,480	1,093
Classification of net deferred income taxes liabilities:		
Included in current liabilities	(5)	65
Included in noncurrent liabilities	1,485	1,028
Total net deferred income taxes liabilities	$ 1,480	$ 1,093

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

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

	Year Ended December 31,		
	2002	2001	2000
	(dollars in millions)		
Federal statutory income tax rate	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:			
State income tax (net of federal benefit)	$ 5.4	$ 5.0	$ 4.3
Effect of regulatory treatment of depreciation differences	1.2	1.7	(2.0)
Tax credits, net	(0.6)	(2.5)	0.7
Other, net	(1.7)	(2.3)	0.1
Effective tax rate	39.3%	36.9%	38.1%

At December 31, 2002, PG&E had $794 million of California net operating loss (NOL) carryforwards that will expire if not used by the end of 2012. The California Revenue and Taxation Code has suspended the use of NOL carryforwards for the tax years ending December 31, 2002, and December 31, 2003.

Note 11: Commitments and Contingencies

Commitments

PG&E has substantial financial commitments in connection with agreements entered into supporting its operating, construction, and development activities.

Natural Gas Supply and Transportation Commitments PG&E purchases natural gas directly from producers and marketers in both Canada and the United States. The composition of the portfolio of natural gas procurement contracts has fluctuated, generally based on market conditions.

PG&E also has long-term gas transportation service agreements with various Canadian and interstate pipeline companies. These companies are responsible for transporting PG&E s gas to the California border. The total demand charges that PG&E will pay each year may change due to changes in tariff rates. These agreements include provisions for payment of fixed demand charges for reserving firm pipeline capacity as well as volumetric transportation charges. The total demand and volumetric transportation charges PG&E incurred under these agreements were $101 million in 2002, $239 million in 2001, and $94 million in 2000.

At December 31, 2002, PG&E s obligations for natural gas purchases and gas transportation services were as follows:

	(in millions)
2003	$595
2004	138
2005	83
2006	26
2007	10
Thereafter	
Total	$852

Since PG&E filed for bankruptcy and its credit rating is below investment grade, PG&E uses several different credit arrangements for the purpose of purchasing natural gas. PG&E has a $10 million standby letter of credit and pledges its gas customer accounts receivable. The core gas inventory will be pledged only if PG&E s gas customer accounts receivable are less than the amount that PG&E owes to the gas suppliers. As of

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

December 31, 2002, the accounts receivable were sufficient. Therefore, the core gas inventory has not been pledged. The CPUC authorized PG&E to pledge its gas accounts receivable and core inventory, if necessary, until the earlier of:

May 1, 2003; or

15 days after an upgrade of the credit rating of PG&E s mortgage bonds to at least BBB- by S&P or Baa3 by Moody s; or

The effective date of a plan of reorganization; or

The dismissal or conversion of PG&E s bankruptcy proceeding.

At December 31, 2002, the pledged amount for total gas accounts receivable was $513 million.

Power Purchase Agreements

Qualifying Facilities PG&E is required by CPUC decisions to purchase energy and capacity from independent power producers that are QFs under the Public Utility Regulatory Policies Act of 1978 (PURPA). Pursuant to PURPA, the CPUC required California IOUs to enter into a series of long-term power purchase agreements (PPAs) with QFs and approved the applicable terms, conditions, price options and eligibility requirements. The PPAs with QFs require PG&E to pay for energy and capacity. Energy payments are based on the QF s actual electrical output and CPUC-approved energy prices, while capacity payments are based on the QF s total available capacity and contractual capacity commitment. Capacity payments may be reduced or increased if the facility fails to meet or, alternatively, exceeds performance requirements specified in the applicable PPAs. PG&E recovers its costs incurred from these contracts through electric revenues billed to the customers. Most of the PPAs with QFs expire on various dates through 2028. PG&E s PPAs with QFs accounted for approximately 25 percent of the 2002 electricity deliveries and approximately 21 percent of the 2001 electricity deliveries. There was no single agreement that accounted for more than 5 percent of PG&E s electricity deliveries in 2002 or 2001.

As a result of the energy crisis and PG&E s bankruptcy filing, a number of QFs requested the Bankruptcy Court to either (1) terminate their contracts requiring them to sell power to PG&E, or (2) have the contracts suspended for the summer of 2001 so the QFs could sell power at market rates to PG&E. The Bankruptcy Court ordered the QFs to directly negotiate with PG&E. In July 2001, 197 QFs elected to adopt CPUC-approved amendments to their PPAs to fix their energy payments at $0.054 per kWh for five years.

In December 2001, the Bankruptcy Court approved supplemental agreements between PG&E and most QFs to resolve the applicable interest rate to be applied to pre-petition amounts owed to QFs. The supplemental agreements (1) set the interest rate for pre-petition payables at 5 percent, (2) provide for a catch-up payment of all accrued and unpaid interest through the initial payment date, and (3) depending on the amount owed, provide for either (a) payment of the principal and interest amount of the pre-petition payable, or (b) payment in 6 or 12 monthly payments beginning on the last business day of the month during which the Bankruptcy Court approval was granted. In the event the effective date of a plan of reorganization occurs before the last monthly payment is made, the remaining unpaid principal and unpaid interest shall be paid on the effective date. The total amount PG&E owed to QFs when it filed for bankruptcy protection was approximately $1 billion. The principal payments to the QFs amounted to $901 million in 2002 and the interest payments amounted to $44 million in 2002 and $16 million in 2001.

Through December 31, 2002, 264 of 313 QFs had signed assumption and/or supplemental agreements. PG&E believes it will be able to enter into similar supplemental agreements with some of the remaining QFs.

Irrigation Districts and Water Agencies PG&E has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, PG&E must make (1) specified semi-annual minimum payments based on the irrigation districts and water agencies debt service requirements, whether or

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

not any energy is supplied (subject to the supplier s retention of the FERC s authorization), and (2) variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. PG&E s PPAs with irrigation districts and water agencies accounted for approximately 4 percent of the 2002 electricity deliveries and accounted for approximately 3 percent of the 2001 electricity deliveries.

Bilateral Power Purchase Contracts Despite the lack of established criteria for cost recovery from the CPUC, PG&E entered into several bilateral forward electric contracts in October 2000 to stabilize the escalating costs of purchasing power. Several of these contracts were terminated by the other parties because either PG&E filed for bankruptcy or PG&E s credit rating declined to below investment grade. As stated in the contracts, the contracts must be settled at the market value on the termination date. The estimated (pre-tax) net gain on the terminated contracts of $552 million in 2001 was used to reduce the cost of electricity in PG&E s Consolidated Statements of Operations.

At December 31, 2002, PG&E had outstanding two bilateral forward electric contracts, which will expire in 2003. The undiscounted future minimum energy payments due under these contracts are $196 million in 2003. Under the normal purchases and sales accounting exemption of SFAS No. 133, PG&E does not recognize the cost of the bilateral contracts until the energy is delivered. At December 31, 2002, the outstanding bilateral contracts had an estimated negative market value of $36 million. This value would be recorded as a cost of electricity in the Consolidated Statements of Operations if these contracts failed to meet the normal purchases and sales exemption. The provisions of one of the contracts allows the other party to terminate the contract without penalty at fair value while PG&E is in a Chapter 11 bankruptcy filing. PG&E expects that the physical delivery of electricity will continue through the duration of the contract period and that the contracts will continue to meet the normal purchases and sales exemptions.

Other California Senate Bill 1078 (SB 1078), requires private utilities to increase their renewable energy supplies by 1 percent a year until these supplies are 20 percent of their generation supply portfolio, provided sufficient funds are available to cover any above-market costs of renewables. Utilities must meet the 20 percent of their generation supply portfolio no later than 2017.

In November 2002, PG&E entered into four contracts with renewable energy suppliers that would obligate PG&E and the DWR upon the occurrence of certain conditions. Subsequently, in February 2003, one of the contracts was terminated. The terms of these contracts with the renewable energy suppliers are for five years commencing on or after January 1, 2003. PG&E will reimburse the DWR for the cost of the contracts in the first year or until PG&E attains an investment grade credit rating, whichever comes first. PG&E has proposed to recover the costs of these contracts through its Energy Resource Recovery Account.

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

	Year Ended December 31,		
	2002	2001	2000
	(in millions, except gigawatt-hours)		
Gigawatt-hours received	28,088	23,732	26,027
QF Energy payments	$ 1,051	$ 1,454	$ 1,549
QF Capacity payments	506	473	519
Irrigation district and water agency payments	57	54	56
Bilateral payments	196	155	53

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

At December 31, 2002, the undiscounted future expected PPA payments were as follows:

	QF		Irrigation District & Water Agency			Other		
	Energy	Capacity	Operations & Maintenance	Debt Service	Bilateral Energy	Energy	Capacity	Total
				(in millions)				
2003	$1,150	$ 530	$ 38	$ 28	$196	$ 14	$ 28	$ 1,984
2004	1,080	520	31	28		14	28	1,701
2005	960	490	26	26		14	28	1,544
2006	880	470	27	27		14	28	1,446
2007	830	450	28	27		14	28	1,377
Thereafter	5,000	2,800	524	168				8,492
Total	$9,900	$5,260	$674	$304	$196	$ 70	$140	$16,544

WAPA Sales Contract Commitments In 1967, PG&E and the Western Area Power Administration (WAPA) entered into a long-term power contract governing (1) the interconnection of PG&E s and WAPA s transmission systems, (2) the use of PG&E s transmission and distribution system by WAPA, and (3) the integration of PG&E s and WAPA s loads and resources. The contract gave PG&E access to surplus hydroelectric power at low prices and obligated PG&E to provide WAPA with electricity when its own resources were not sufficient to meet its requirements. The contract terminates on December 31, 2004.

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

The costs going forward to procure power to fulfill PG&E s obligations to WAPA under the contract is uncertain. However, PG&E expects that the cost of meeting its obligation to WAPA may be greater than the price PG&E receives from WAPA under the contract. Under AB 1890, PG&E s retail ratepayers pay for this difference as a stranded power purchase cost. The amount of the difference between PG&E 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 electricity WAPA will need from PG&E 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 PG&E was 3,619 gigawatt-hour (GWh) in 2002, 4,823 GWh in 2001, and 5,120 GWh in 2000.

Nuclear Fuel Agreements PG&E has purchase agreements for nuclear fuel components and services for use in operating the Diablo Canyon generating facility. These agreements run from two to five years and are intended to ensure long-term fuel supply, but also permit PG&E the flexibility to take advantage of short-term supply opportunities. Deliveries under six of the eight contracts in place at the end of 2002 will end by 2005. In most cases, PG&E s nuclear fuel contracts are requirements-based and dependent on PG&E s continued operation of its Diablo Canyon generating plant.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

At December 31, 2002, the undiscounted obligations under nuclear fuel agreements were as follows:

	(in millions)
2003	$ 59
2004	50
2005	12
2006	13
2007	14
Thereafter	65
Total	$213

Payments for nuclear fuel amounted to $70 million in 2002, $50 million in 2001, and $78 million in 2000.

PG&E 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.

Operating Leases

PG&E has entered into several operating lease agreements for office space. The leases expire on various dates between 2003 and 2009.

At December 31, 2002, the approximate obligations under these operating lease agreements were as follows:

	(in millions)
2003	$ 9
2004	10
2005	9
2006	9
2007	9
Thereafter	9
Total	$ 55

The operating expenses related to the operating lease agreements for office space amounted $13 million in 2002, $11 million in 2001, and $12 million in 2000.

Other Commitments

Capital Infusion Agreement PG&E has entered into Capital Infusion Agreements, which obligate PG&E to make scheduled payments to investment partnerships in return for a limited partnership interest. The CPUC has approved PG&E s investment in the non-regulated subsidiaries, which are mainly engaged in the purchase of residential real estate property. The Capital Infusion Agreements are secured by PG&E s interest in the partnership and PG&E is fully responsible for its future obligations under these agreements. See discussion of unconsolidated subsidiaries in Note 1.

Under the agreements, PG&E is in default if PG&E (1) becomes insolvent or files for bankruptcy, or (2) fails to make any of its scheduled payments. While technically in default as of December 31, 2002, PG&E is current on all its payments and expects to make all future payments when they become due. PG&E believes the technical default will not result in a loss in PG&E s investment interest.

PG&E s contributions to the investment partnerships amounted to $7 million in 2002, $9 million in 2001, and $4 million in 2000.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Diablo Canyon Power-Plant Turbines PG&E has entered into a contract to retrofit its six low-pressure turbines at Diablo Canyon Unit 1 and Unit 2. These turbine retrofits will (1) improve reliability of the turbine equipment, (2) reduce maintenance costs, and (3) produce more electricity through improved efficiency. The installation of the turbine retrofits is expected to begin in Fall 2005. Progress payments for the turbines will begin in 2003 as certain milestones are reached. PG&E expects all costs incurred under the contract to be capitalized, and included in Property, Plant and Equipment in the Consolidated Balance Sheets and amortized over the useful life of the asset.

Self-Generation Incentive Program The CPUC directed the state s larger IOUs to fund load-control and self-generation initiatives at an annual cost of $138 million for four years beginning in 2001. PG&E s portion of the annual costs is $3 million for load control and $60 million for self-generation initiatives per year. Under the self-generation incentive portion, PG&E offers lump sum rebates to customers who install up to one-and-a-half megawatts of clean on-site distributed energy. As of December 31, 2002, PG&E has signed contracts with 54 customers. PG&E s estimated obligation under these contracts is $16 million. PG&E expects the majority of the contract obligations to be fulfilled in 2003 and payment obligations to be paid to the customers. However, customers have the option of extending the installment date by up to another 180 days due to unforeseen events (such as delays in equipment arrival, delays in permitting process, etc.), which would in turn delay the incentive payments.

The costs associated with the incentive portion of the self-generation program amounted to $7 million in 2002 with no similar costs incurred in 2001 and 2000.

The CPUC has stated that it will allow costs of this program which are not recovered during the rate freeze to be recorded in a balancing account and recovered after the rate freeze ends. PG&E receives no rate of return on its investment in these programs, and the CPUC has not addressed how these costs will be recovered. See discussion of PG&E s policy regarding balancing accounts in Note 1.

Telecommunications PG&E has several cancelable contracts to support PG&E s local and long-distance telecommunication needs. The terms of the contracts require PG&E to give a one-year notice in order to terminate the service. Therefore, PG&E s future commitment is the annual amount, less any amount already paid.

The costs incurred under these contracts amounted to $7 million in 2002, $9 million in 2001, and $5 million in 2000.

At December 31, 2002, the future minimum payments related to other commitments as described above are as follows:

	(in millions)
2003	$ 51
2004	35
2005	30
2006	15
2007	2
Thereafter	2
Total	$135

Contingencies

Nuclear Insurance PG&E has several types of nuclear insurance for Diablo Canyon and Humboldt Bay. PG&E has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). NEIL is a mutual insurer owned by utilities with nuclear facilities. Under

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

this insurance, if a nuclear generating facility insured by NEIL suffers severe losses and those losses exceed the resources of NEIL, PG&E may be responsible for additional premiums of up to $32 million to cover property damages and business interruption for Diablo Canyon and up to $1.4 million to cover property damages for Humboldt Bay.

Under federal law, the Price-Anderson Act (Act) public liability claims from a nuclear incident are limited to $9.5 billion. As required by the Act, PG&E has purchased the maximum available public liability insurance of $300 million for Diablo Canyon. The balance of the $9.5 billion of liability protection is covered by a loss-sharing program (secondary financial protection) among utilities owning nuclear reactors. Under the Act, secondary financial protection is required for all reactors of 100 megawatts (MW) or higher. If a nuclear incident results in costs in excess of $300 million, then PG&E may be responsible for up to $88 million per reactor with payments in each year limited to a maximum of $10 million per incident until PG&E has fully paid its share of the liability. Since PG&E has two nuclear reactors of over 100 MW, PG&E may be assessed up to $176 million per incident with payments in each year limited to a maximum of $20 million per incident. The 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.

Additionally, PG&E has purchased $53.3 million of private liability insurance for Humboldt Bay and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of private liability insurance for Humboldt Bay.

Workers Compensation Security PG&E is self insured for workers compensation. PG&E must deposit collateral with the State Department of Industrial Relations (DIR) to maintain its status as a self-insurer for workers compensation claims made against PG&E. Acceptable forms of collateral include surety bonds, letters of credit, cash, or securities. PG&E currently provides collateral in the form of approximately $365 million in surety bonds.

In February 2001, several surety companies provided cancellation notices because of PG&E s financial situation. The DIR has not agreed to release the canceling sureties from their obligations for claims occurring prior to the cancellation and has continued to apply the cancelled bond amounts, totaling $185 million, towards the $365 million amount of collateral. PG&E was able to supplement the difference through three additional active surety bonds totaling $180 million. At December 31, 2002, the cancelled bonds have not impacted PG&E s self-insured status under California law. PG&E Corporation has guaranteed PG&E s reimbursement obligation associated with these surety bonds and PG&E s underlying obligation to pay workers compensation claims.

Environmental Matters PG&E may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by PG&E for the storage, recycling, or disposal of potentially hazardous materials. Under federal and California laws, PG&E may be responsible for remediation of hazardous substances even if PG&E did not deposit those substances on the site.

PG&E records an environmental remediation liability when site assessments indicate remediation is probable and a range of likely clean-up costs can be reasonably estimated. PG&E reviews its remediation liability on a quarterly basis for each site that may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure using (1) current technology, (2) enacted laws and regulations, (3) experience gained at similar sites, and (4) the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, PG&E records the lower end of this range.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

PG&E had an undiscounted environmental remediation liability of $331 million at December 31, 2002, and $295 million at December 31, 2001. The $331 million accrued at December 31, 2002, included (1) $138 million related to the pre-closing remediation liability associated with divested generation facilities, and (2) $193 million related to remediation costs for those generation facilities that PG&E still owns, manufactured gas plant sites, gas gathering sites, and compressor stations. Of the $331 million environmental remediation liability, PG&E has recovered $188 million through rates charged to its customers, and expects to recover approximately $84 million of the balance in future rates. PG&E also is recovering its costs from insurance carriers and from other third parties whenever it is possible.

The cost of the hazardous substance remediation ultimately undertaken by PG&E is difficult to estimate. A change in the estimate may occur in the near term due to uncertainty concerning PG&E s responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. PG&E estimates the upper limit of the range using assumptions least favorable to PG&E, which is based upon a range of reasonably possible outcomes. PG&E 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) PG&E is found to be responsible for clean-up costs at additional sites.

On June 28, 2001, the Bankruptcy Court authorized PG&E to continue its hazardous waste remediation program and to expend (1) up to $22 million in hazardous substance remediation programs and procedures in each calendar year in which the Chapter 11 case is pending; and (2) any additional amounts in emergency situations involving post-petition releases or threatened releases of hazardous substances subject to the Bankruptcy Court s specific approval.

The California Attorney General, on behalf of various state environmental agencies, filed claims in PG&E s bankruptcy proceeding for environmental remediation at numerous sites totaling approximately $770 million. For most if not all of these sites, PG&E is in the process of remediation in cooperation with the relevant agencies and other parties responsible for contributing to the clean-up in the normal course of business. Since PG&E s proposed plan of reorganization provides that PG&E intends to respond to these types of claims in the regular course of business, and since PG&E has not argued that the bankruptcy proceeding relieves PG&E of its obligations to respond to valid environmental remediation orders, PG&E believes the claims seeking specific cash recoveries are invalid.

Global climate change is a significant environmental issue that is likely to require sustained global action and investment over many decades. PG&E 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 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. PG&E emits varying quantities of these greenhouse gases, including carbon dioxide and methane, in the course of their operations. Depending on the ultimate regulatory regime put into place for greenhouse gases, PG&E 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 PG&E s financial condition or result of operations.

PG&E is 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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

Legal Matters

In the normal course of business, PG&E is named as a party in a number of claims and lawsuits. The most significant of these are discussed below. PG&E s Chapter 11 bankruptcy filing on April 6, 2001, discussed in Note 2 of the Notes to the Consolidated Financial Statements, automatically stayed the litigation described below against PG&E, except as otherwise noted.

Chromium Litigation

There are 15 civil suits pending against PG&E in several California state courts. One of these suits also names PG&E Corporation as a defendant. One additional civil suit, *Kearney v. Pacific Gas and Electric Company*, was filed against PG&E and PG&E Corporation after PG&E s bankruptcy filing and was dismissed without prejudice while the plaintiffs sought the right to file and pursue late claims in the Bankruptcy Court. In the *Kearney* case, the Bankruptcy Court ruled that the six adult plaintiffs could not file untimely bankruptcy claims against PG&E. The court also ruled that the 24 minor plaintiffs could file untimely bankruptcy claims against PG&E. The suits allege personal injuries, wrongful death, and loss of consortium and seek compensatory and punitive damages based on claims arising from alleged exposure to chromium in the vicinity of PG&E s gas compressor stations at Hinkley and Kettleman, California, and the area of California near Topock, Arizona. Currently, there are approximately 1,200 plaintiffs in the chromium litigation cases.

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

In the case of *Adams v. Pacific Gas and Electric Company and Betz Chemical Company*, after a hearing on July 17, 2002, the state court dismissed 35 plaintiffs with prejudice because their claims are barred by the statute of limitations. The state court dismissed another 65 plaintiffs without prejudice, so these plaintiffs may attempt to prove that their claims are not barred by the statute of limitations. Thirty of these plaintiffs filed a Fourth Amended Complaint on October 16, 2002. The other 35 plaintiffs who were given leave to amend have been dismissed with prejudice for failure to amend.

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

PG&E has recorded a reserve in its financial statements in the amount of $160 million for these matters. PG&E believes that, after taking into account the reserves recorded at December 31, 2002, the ultimate outcome of this matter will not have a material adverse impact on PG&E s financial condition or future results of operations.

Natural Gas Royalties Litigation

This litigation involves the consolidation of approximately 77 False Claims Act cases filed in various federal district courts by Jack J. Grynberg (called a relator in the parlance of the False Claims Act) on behalf of the United States of America, against more than 330 defendants, including PG&E and PG&E GTN. The cases were

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

consolidated for pretrial purposes in the District of Wyoming. The current case grows out of prior litigation brought by the same relator in 1995 that was dismissed in 1998.

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

The complaints allege that the various defendants (most of which are pipeline companies or their affiliates) incorrectly measured the volume and heat content of natural gas produced from federal or Indian leases. As a result, it is alleged that the defendants underpaid, or caused others to underpay, the royalties that were due to the United States for the production of natural gas from those leases. The complaints do not seek a specific dollar amount or quantify the royalties claim. The complaints seek unspecified treble damages, civil penalties, and expenses associated with the litigation.

The relator has filed a claim in PG&E s bankruptcy case for $2.5 billion, $2 billion of which is based upon the plaintiff s calculation of penalties sought against PG&E.

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

Order Instituting Investigation into Holding Company Activities and Related Litigation

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

On January 9, 2002, the CPUC issued an interim decision and order interpreting the first priority condition adopted in the CPUC s holding company decision. This condition requires that the capital requirements of PG&E, as determined to be necessary and prudent to meet PG&E s obligation to serve or to operate PG&E in a prudent and efficient manner, be given first priority by the board of directors of the holding company. In the interim order, the CPUC stated, the first priority condition does not preclude the requirement that the holding company infuse all types of capital into their respective utility subsidiaries where necessary to fulfill PG&E s obligation to serve. The three major California IOUs and their parent holding companies had opposed the broader interpretation, first contained in a proposed decision released for comment on December 26, 2001, 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. The utilities applications for rehearing were denied on July 17, 2002.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

In a related decision, the CPUC denied the motions filed by the California utility holding companies to dismiss the holding companies from the pending investigation on the basis that the CPUC lacks jurisdiction over the holding companies. However, in the interim decision interpreting the first priority condition discussed above, the CPUC separately dismissed PG&E Corporation (but no other utility holding company) as a respondent to the proceeding. In its written decision adopted on January 9, 2002, the CPUC stated that PG&E Corporation was being dismissed so that an appropriate legal forum could decide expeditiously whether adoption of the Plan would violate the first priority condition. The utilities applications for rehearing were denied on July 17, 2002.

The holding companies have filed petitions for review of both the CPUC s capital requirements and jurisdiction decisions in several state appellate courts, and the utilities also have filed petitions for review of the capital requirements decision with the California appellate courts. The CPUC moved to consolidate all proceedings in the San Francisco state appellate court and requested that the court extend the deadline by which the CPUC must file its responses to the petitions for review until after the consolidation occurred. The CPUC s request for consolidation was granted and all of the petitions are now before the First Appellate District in San Francisco, California.

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

Among other allegations, the California Attorney General alleged that, through PG&E s bankruptcy proceedings, PG&E Corporation and PG&E engaged in unlawful, unfair, and fraudulent business practices in alleged violation of California Business and Professions Code Section 17200 (Section 17200) by seeking to implement the transactions contemplated in the Plan filed in PG&E s bankruptcy proceeding. The complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from PG&E. On February 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the California Attorney General s complaint to the Bankruptcy Court. On February 15, 2002, PG&E Corporation filed a motion to dismiss the lawsuit, or in the alternative, to stay the suit with the Bankruptcy Court. Subsequently, the Attorney General filed a motion to remand the action to state court. In June 2002, the Bankruptcy Court held that federal law preempted the California Attorney General s allegations concerning PG&E Corporation s participation in PG&E s bankruptcy proceedings. The Bankruptcy Court directed the California Attorney General to file an amended complaint omitting these allegations and remanded the amended complaint to the San Francisco Superior Court. Both parties have appealed the Bankruptcy Court s remand order. The appeal and cross-appeal are pending in the U.S. District Court for the Northern District of California.

On August 9, 2002, the California Attorney General filed its amended complaint in the San Francisco Superior Court, omitting the allegations concerning PG&E Corporation s participation in PG&E s bankruptcy proceedings. PG&E Corporation and the directors named in the complaint have filed a motion to strike certain allegations of the amended complaint. Those motions are pending.

In addition, a second case, entitled *Cynthia Behr v. PG&E Corporation, et al.*, was filed on February 14, 2002, by a private plaintiff (who also has filed a claim in bankruptcy) in Santa Clara Superior Court also alleging a violation of Section 17200. The Behr complaint also names the directors of PG&E Corporation and PG&E as defendants. The allegations of the complaint are similar to the allegations contained in the California Attorney General s complaint but also include allegations of fraudulent transfer and violation of the California bulk sales laws. Plaintiff requests the same remedies as the California Attorney General s case and in addition requests damages, attachment, and restraints upon the transfer of defendants property. On March 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the complaint to the Bankruptcy Court. Subsequently, the plaintiff filed a motion to remand the action to state court. In its June 2002 ruling mentioned

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

above as to the Attorney General s and the City and County s cases, the Bankruptcy Court retained jurisdiction over Behr s fraudulent transfer claim and bulk sales claim, finding them to belong to PG&E s estate. The Bankruptcy Court remanded Behr s Section 17200 claim to the Santa Clara Superior Court. Both parties have appealed the Bankruptcy Court s remand order. The appeal and cross-appeal are pending in the U.S. District Court for the Northern District of California.

Following remand, PG&E Corporation and PG&E moved to have the Behr case coordinated with the City s case described above. That motion was granted, and the Behr case will now proceed in San Francisco Superior Court.

PG&E believes that it has complied with applicable statutes, CPUC decisions, rules, and orders. PG&E, however, cannot predict what the outcome of the CPUC s investigation will be or whether the outcome will have a material adverse effect on its results of operations or financial condition. PG&E believes that the allegations of the complaints are without merit and will vigorously respond to and defend the litigation. PG&E cannot predict whether the outcome of the litigation will have a material adverse effect on its results of operations or financial condition.

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

On February 27, 2002, a group of 25 ratepayers filed a complaint against PG&E at the CPUC demanding an immediate reduction of approximately $0.035 kWh in allegedly excessive electric rates and a refund of alleged recent over-collections in electric revenue since June 1, 2001. The complaint claims that electric rate surcharges adopted in the first quarter of 2001 due to the high cost of wholesale power (surcharges that increased the average electric rate by $0.04 per kWh) became excessive later in 2001. (In January 2001, the CPUC authorized a $0.01 per kWh increase to pay for energy procurement costs. In March 2001, the CPUC authorized an additional $0.03 per kWh electric rate increase as of March 27, 2001, to pay for energy procurement costs, which PG&E began to collect in June 2001.) The only alleged over-collection amount calculated in the complaint is approximately $400 million during the last quarter of 2001. On April 2, 2002, PG&E filed an answer, arguing that the complaint should be denied and dismissed immediately as an impermissible collateral action and on the basis that the alleged facts, even if assumed to be true, do not establish that currently authorized electric rates are not reasonable. On May 10, 2002, PG&E filed a motion to dismiss the complaint. The CPUC has not yet issued a decision. PG&E believes that the ultimate outcome of this matter will not have a material adverse effect on its financial condition or results of operations.

Recorded Liability for Legal Matters

In accordance with SFAS No. 5, Accounting for Contingencies, PG&E makes a provision for a liability when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular case. In 2001, PG&E increased its provision for legal matters due to a significant case that had a potential material financial impact on PG&E. In 2002, PG&E adjusted its provision again due to the settlement of that case without any damages awarded to the other parties.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

The provision for legal matters is included in PG&E s other noncurrent liabilities in the Consolidated Balance Sheets. The following table reflects the current year s activity to the recorded liability for legal matters for PG&E:

	2002	2001
	(in millions)	
Beginning balance, January 1,	$209	$185
Provision for liabilities	27	7
Payments	(5)	(2)
Adjustments	(29)	19
Ending balance, December 31,	$202	$209

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000 (Continued)

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

	Quarter Ended			
	December 31	September 30	June 30	March 31
	(in millions)			
2002				
Operating revenues	$2,398	$2,949	$2,714	$ 2,453
Operating income	547	1,059	1,059	1,248
Net income	227	527	469	596
Income available for common stock	221	520	463	590
2001				
Operating revenues	$2,654	$2,937	$2,309	$ 2,562
Operating income (loss)	1,134	1,428	1,336	(1,420)
Net income (loss)	563	744	702	(994)
Income (Loss) available for (allocated to) common stock	557	737	696	(1,000)

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE

SIX MONTHS ENDED JUNE 30, 2003

Note 1: General

Organization and Basis of Presentation

Pacific Gas and Electric Company (PG&E), incorporated in California in 1905, is the predecessor and a wholly owned subsidiary of PG&E Corporation. PG&E provides electric service to approximately 4.8 million customers and natural gas service to approximately 3.9 million customers in Northern and Central California and is headquartered in San Francisco. As discussed further in Note 2, on April 6, 2001, PG&E filed a voluntary petition for relief under the provisions of Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the U.S. Bankruptcy Court for the Northern District of California (Bankruptcy Court). Pursuant to Chapter 11 of the Bankruptcy Code (Chapter 11), PG&E retains control of its assets and is authorized to operate its business as a debtor-in-possession while subject to the jurisdiction of the Bankruptcy Court.

PG&E s unaudited Consolidated Financial Statements and unaudited Notes to the Consolidated Financial Statements include its accounts as well as those of its wholly owned and controlled subsidiaries.

PG&E believes that the accompanying Consolidated Financial Statements reflect all adjustments that are necessary to present a fair statement of the consolidated financial position and results of operations for the interim periods. All material adjustments are of a normal recurring nature unless otherwise disclosed herein. All significant intercompany transactions have been eliminated from the Consolidated Financial Statements.

These financial statements for the six months ended June 30, 2003 should be read in conjunction with PG&E s Consolidated Financial Statements and Notes to the Consolidated Financial Statements included on pages F-1 to F-59 of this Prospectus, and PG&E s other reports filed with the Securities and Exchange Commission (SEC) since the combined 2002 Annual Report on Form 10-K, as amended, was filed.

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 from these estimates.

PG&E s Consolidated Financial Statements have been prepared in accordance with the American Institute of Certified Public Accountants Statement of Position (SOP) 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code, and on a going-concern basis, which contemplates continuity of operation, realization of assets, and liquidation of liabilities in the ordinary course of business. As a result of PG&E s Chapter 11 filing, the realization of assets and liquidation of liabilities are subject to uncertainty. Under SOP 90-7, certain liabilities of PG&E existing prior to its Chapter 11 filing are classified as Liabilities Subject to Compromise on the Consolidated Balance Sheets. Additionally, professional fees and expenses directly related to PG&E s Chapter 11 proceeding and interest income on funds accumulated during the Chapter 11 proceedings are reported separately as reorganization items. Finally, the extent to which PG&E s reported interest expense differs from its stated contractual interest is disclosed on PG&E s Consolidated Statements of Operations.

Historically, PG&E has presented its Notes to the Consolidated Financial Statements combined with its parent PG&E Corporation. These Notes to the Consolidated Financial Statements present only PG&E financial information. The modifications did not affect the consolidated net income and the Notes to the Consolidated Financial Statements have been modified to conform to this presentation.

Adoption of New Accounting Policies and Summary of Significant Accounting Policies

The accounting policies used by PG&E 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). Except as disclosed below, PG&E is following the same accounting policies discussed in the Notes to the Consolidated Financial Statements for the years ended December 31, 2002, 2001, and 2000 included in this Registration Statement.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

Accounting for Asset Retirement Obligations

On January 1, 2003, PG&E adopted Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143). SFAS No. 143 provides accounting requirements for costs associated with legal obligations to retire tangible long-lived assets. SFAS No. 143 requires that an asset retirement obligation be recorded at fair value in the period in which it is incurred, if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS 143 and costs recovered through the ratemaking process.

The impact of adopting SFAS No. 143 were as follows:

PG&E has identified its nuclear generation and certain fossil generation facilities as having asset retirement obligations as of January 1, 2003. No additional asset retirement obligations had been identified as of June 30, 2003. Through December 31, 2002, PG&E had recorded $1.4 billion for its nuclear power facilities and fossil generation assets decommissioning obligations in Accumulated Depreciation and Decommissioning in the Consolidated Balance Sheet.

Upon adoption of SFAS No. 143, PG&E reclassified the decommissioning liabilities recorded through December 31, 2002, as Asset Retirement Obligations in the Consolidated Balance Sheets. To record the decommissioning liabilities at fair value as required by SFAS No. 143, PG&E then reduced the asset retirement obligations by $53 million. PG&E increased its Property, Plant and Equipment balance by $332 million to reflect the fair value of the asset retirement costs as of the date the obligation was incurred, less accumulated depreciation from the date the obligation was incurred through December 31, 2002. Finally, PG&E recorded a regulatory liability of $387 million to reflect the cumulative effect of adoption for its nuclear facilities. This regulatory liability represents timing differences between recognition of nuclear decommissioning obligations in accordance with GAAP and ratemaking purposes. The cumulative effect of the change in accounting principle for PG&E s fossil facilities as a result of adopting SFAS No. 143 was a loss of $1 million, after-tax.

If SFAS No. 143 had been adopted on January 1, 2002, the pro forma effects on earnings of the accounting change for the three and six months ended June 30, 2002, would not have been material. The amounts recorded upon adoption of SFAS No. 143 reflect the pro forma effects on the Consolidated Balance Sheet had SFAS No. 143 been adopted on December 31, 2002.

PG&E has established trust funds that are legally restricted for purposes of settling its nuclear decommissioning obligations. As of June 30, 2003, the fair value of these trust funds was approximately $1.4 billion.

PG&E may have potential asset retirement obligations under various land right documents associated with its transmission and distribution facilities. The majority of PG&E s land rights are perpetual. Any non-perpetual land rights generally are renewed continuously because PG&E intends to utilize these facilities indefinitely. Since the timing and extent of any potential asset retirements are unknown, the fair value of any obligations associated with these facilities cannot be reasonably estimated.

PG&E collects estimated removal costs in rates through depreciation in accordance with regulatory treatment. These amounts do not represent SFAS No. 143 asset retirement obligations and will continue to be recorded in accumulated depreciation. As of June 30, 2003, PG&E s estimated removal costs recorded in accumulated depreciation were approximately $1.7 billion.

Stock-Based Compensation

PG&E accounts for stock-based compensation using the intrinsic value method in accordance with the provisions of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees, as

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

allowed by SFAS No. 123, Accounting for Stock-Based Compensation, (SFAS No. 123), as amended by SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure, an Amendment of FASB Statement No. 123. Under the intrinsic value method, PG&E does not recognize any compensation expense for stock options, as the exercise price is equal to the fair market value of a share of PG&E Corporation common stock at the time the options are granted. Had compensation expense been recognized using the fair value-based method under SFAS No. 123, PG&E s pro forma consolidated earnings (loss) and earnings (loss) would have been as follows:

	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(in millions)	
Net earnings/(loss) available for common stock:		
As reported	$260	$1,053
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	4	4
Pro forma	$256	$1,049

As of June 30, 2003, a total of 0.9 million shares of restricted PG&E Corporation common stock had been awarded to eligible employees of PG&E. The shares were granted with restrictions and are subject to forfeiture unless certain conditions are met.

The restricted shares were issued at the grant date and are held in an escrow account. The shares become available to the employees as the restrictions lapse. In general, the restrictions on 80 percent of the shares lapse automatically over a period of four years at the rate of 20 percent per year. Restrictions to the remaining 20 percent of the shares will lapse at a rate of 5 percent per year if PG&E Corporation is in the top quartile of its comparator group as measured by annual total shareholder return for each year ending immediately before each annual lapse date.

Total compensation expense resulting from the restricted stock issuance reflected on PG&E s Consolidated Statements of Operations was $1.9 million for the six-month periods ended June 30, 2003.

Comprehensive Income

PG&E s comprehensive income consists principally of changes in the market value of certain cash flow hedges under SFAS No. 133 and the effects of the remeasurement of the defined benefit pension plan.

	2003	2002
	(in millions)	
Six months ended June 30		
Net income available for common stock	$260	$1,053
Foreign currency translation adjustment		2
Retirement plan remeasurement (Note 5)	(60)	
Comprehensive income	$200	$1,055

The above changes to comprehensive income are stated net of income tax benefits of $41 million for the three-month period ended June 30, 2002.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

Related Party Transactions

In accordance with various agreements, PG&E and other subsidiaries of PG&E Corporation provide and receive various services to and from their parent, PG&E Corporation. PG&E and PG&E Corporation exchange administrative and professional support services in support of operations. These services are priced either at the fully loaded cost (i.e., direct costs and allocation of overhead costs) or at the higher of fully loaded cost or fair market value, depending on the nature of the services provided. PG&E Corporation also allocates certain other corporate administrative and general costs to PG&E and other subsidiaries using a variety of factors, including the number of employees, operating expenses excluding fuel purchases, total assets, and other cost-causal methods. PG&E purchases transmission services from PG&E Gas Transmission, Northwest Corporation (PG&E GTN). Effective April 1, 2003, PG&E no longer purchases gas commodity from PG&E Energy Trading (PG&E ET). Both PG&E GTN and PG&E ET are subsidiaries of PG&E National Energy Group (PG&E NEG), a subsidiary of PG&E Corporation. PG&E continues to sell reservation and other ancillary services to PG&E ET. These services are priced at either tariff rates or fair market value depending on the nature of the services provided. PG&E s significant related party transactions and related receivable (payable) balances were as follows:

	Six Months Ended June 30,		Receivable (Payable) Balance Outstanding at	
	2003	2002	June 30, 2003	December 31, 2002
			(in millions)	
Revenues from:				
Administrative services provided to PG&E Corporation	$ 4	$ 3	$ 2	$ 1
Gas reservation services provided to PG&E ET	4	6		
Contribution in aid of construction received from PG&E NEG				3
Trade deposit due from PG&E GTN	3		15	12
Expenses from:				
Administrative services received from PG&E Corporation	$ 98	$ 50	$ (358)	$ (289)
Interest accrued on pre-petition liability due to PG&E Corporation	4		(2)	(2)
Administrative services received from PG&E NEG	2		(1)	(2)
Software purchases from PG&E ET	1			
Gas commodity services received from PG&E ET	10	28	(1)	(26)
Gas transmission services received from PG&E GTN	29	22	(8)	(8)
Trade deposit due to PG&E ET	1		(5)	(7)

Payment of outstanding amounts owed to PG&E as of July 8, 2003, the date of PG&E NEG s Chapter 11 filing, are subject to the approval of the Bankruptcy Court.

Accounting Pronouncements Issued But Not Yet Adopted

Changes to Accounting for Certain Derivative Contracts

In June 2003, the Financial Accounting Standards Board (FASB) issued a new Derivatives Implementation Group (DIG) interpretation of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133), Issue No. C20, Scope Exceptions: Interpretation of the Meaning of *Not Clearly and Closely Related* in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature (DIG C20). DIG C20 specifies additional circumstances under which price adjustment features, such as those based on broad market indices, in a derivative contract would not be an impediment to qualifying for the normal purchases and normal sales scope exception under SFAS No. 133. Certain derivative contracts 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. One of

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

the attributes necessary to qualify for the normal purchases and sales exception is that the pricing must be deemed to be clearly and closely related to the asset to be delivered under the contract. Under DIG C20, as long as the price adjustment feature in a contract is expected to be highly correlated to the asset to be delivered under that contract, the use of a broad market index (such as the consumer price index) as a price adjustment feature is considered clearly and closely related. Previously, under DIG C11, Interpretations of Clearly and Closely Related in Contracts That Qualify for the Normal Purchases and Normal Sales Exceptions, (DIG C11) the use of a price adjustment based on a broad market index was not considered to be clearly and closely related to the asset to be delivered, and the contract was not eligible for the normal purchases and sales exception. The guidance in DIG C11 is superseded by DIG C20.

The assessment of whether the contract qualifies for the normal purchase and sales exception, including whether the price adjustment is clearly and closely related to the asset being transacted, must be performed at the inception of the contract.

The implementation guidance in DIG C20 is effective for all existing and all future derivative contracts in the quarter beginning after July 10, 2003 (fourth quarter of 2003). Early application in the third quarter of 2003 is permitted. Application of the DIG C20 guidance to existing contracts that were not previously eligible for the normal purchases and sales exception under DIG C11 will be applied prospectively. The contract s fair value as of the date of adoption of DIG C20 should become the carrying value at that date. PG&E currently is evaluating the impacts, if any, of DIG C20 on its Consolidated Financial Statements.

Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity (SFAS No. 150). SFAS No. 150 addresses concerns of how to measure and classify in the statement of financial position certain financial instruments that have characteristics of both liabilities and equity. The following freestanding financial instruments must be classified as liabilities: mandatorily redeemable financial instruments, obligations to repurchase an issuer s equity shares by transferring assets, and certain obligations to issue a variable number of shares.

The requirements of SFAS No. 150 are applicable to PG&E in the third quarter of 2003. SFAS No. 150 will be implemented by reclassifying and remeasuring PG&E s $137 million of preferred stock with mandatory redemption provisions as a liability, at the present value of the redemption amount using the rate implicit in the contract at inception, without reclassifying prior dividends or accruals. The remeasurement and reclassification will not have an impact on earnings of PG&E. The preferred stock with mandatory redemption provisions are to be measured subsequently at the amount of cash that would be paid under the conditions specified in the contract if settlement occurred at the reporting date. All amounts paid or to be paid to the holders of the financial instruments in excess of the initial measured amount are reflected in interest cost.

Determining Whether an Arrangement Contains a Lease

In May 2003, the EITF reached consensus on EITF 01-8, Determining Whether an Arrangement Contains a Lease (EITF 01-8). EITF 01-8 establishes criteria to be applied to any new or modified agreement in order to ascertain if such agreement is in effect a lease, and subject to lease accounting treatment and disclosure requirements principally found in SFAS No. 13, Accounting for Leases (SFAS No. 13). EITF 01-8 is effective for all new or modified arrangements entered into as of July 1, 2003. PG&E currently is assessing the impact of EITF 01-8.

Amendment of Statement 133 on Derivative Instruments and Hedging Activities

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities (SFAS No. 149). SFAS No. 149 amends and clarifies the accounting and reporting for derivative instruments, including certain derivatives embedded in other contracts, and for hedging activities

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

under SFAS No. 133. SFAS No. 149 clarifies under what circumstances a contract with an initial net investment meets the characteristics of a derivative according to SFAS No. 133 and when a derivative contains a financing component that warrants special reporting in the statement of cash flows. The provisions of SFAS No. 149 that relate to SFAS No. 133 Implementation Issues that have been effective for periods that began prior to June 15, 2003, should continue to be applied in accordance with their respective effective dates.

The requirements of SFAS No. 149 are effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. PG&E currently is evaluating the impacts, if any, of SFAS No. 149 on its Consolidated Financial Statements.

Consolidation of Variable Interest Entities

In January 2003, the 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 or arrangement with which it is involved. A variable interest entity is an entity that does not have sufficient equity investment at risk to permit the entity to finance its activities without additional subordinated financial support from other parties or an entity where equity investors lack the essential characteristics of a controlling financial interest.

Until the issuance of FIN 46, a 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. There were no new variable interest entities created by PG&E between February 1, 2003, and June 30, 2003. The consolidation requirements are applicable to PG&E in the third quarter of 2003. PG&E is evaluating the impacts of FIN 46 s initial recognition, measurement, and disclosure provisions on the Consolidated Financial Statements, and currently is unable to estimate variable interest entities that will be consolidated or disclosed when FIN 46 becomes effective.

Note 2: Chapter 11 Filing

The discussion of PG&E s Chapter 11 filing matters below should be read in conjunction with Note 2 of the Notes to the Consolidated Financial Statements of PG&E for the years ended December 31, 2002, 2001 and 2000, included herein.

Chapter 11 Filing

On April 6, 2001, PG&E filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. Pursuant to Chapter 11, PG&E retains control of its assets and is authorized to operate its business as a debtor-in-possession while subject to the jurisdiction of the Bankruptcy Court. Subsidiaries of PG&E, including PG&E Funding, LLC (which holds rate reduction bonds) and PG&E Holdings, LLC (which holds stock of PG&E), are not included in PG&E s Chapter 11 filing.

In connection with PG&E s Chapter 11 proceeding, various parties filed claims with the Bankruptcy Court totaling approximately $50.1 billion. Of these claims, approximately $27.0 billion have been disallowed by the Bankruptcy Court due to objections, claim withdrawals, and agreements with claimants. PG&E has objected to, or intends to object to, approximately $5.0 billion of the remaining $23.1 billion of filed claims. These objections relate primarily to the ISO, California Power Exchange (PX), and generator claims. Generator claims could be

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

reduced significantly based on the FERC s March 26, 2003, decision finding that electricity suppliers overcharged California buyers, including California investor-owned utilities (IOUs), from October 2, 2000, to June 20, 2001. In addition, PG&E is in settlement discussions with certain claimants. These settlement discussions could further reduce outstanding claims. Finally, of the remaining $23.1 billion of filed claims, approximately $5.4 billion are expected to pass through the Chapter 11 proceeding and be determined in the appropriate court or other tribunal during or after the Chapter 11 proceeding.

PG&E has recorded its estimate of all valid claims at June 30, 2003, as $9.5 billion of Liabilities Subject to Compromise and $3.0 billion of Long-Term Debt. As of December 31, 2002, PG&E had recorded $9.4 billion of Liabilities Subject to Compromise. The increase from $9.4 billion is primarily due to interest accruals during the six months ended June 30, 2003.

The Bankruptcy Court has authorized certain payments and actions necessary for PG&E to continue its normal business operations while operating as a debtor-in-possession. For example, PG&E is authorized to pay employee wages and benefits, amounts due under contracts with the majority of qualifying facilities (QFs), interest on certain secured and unsecured debt, environmental remediation expenses, and expenditures related to property, plant and equipment. In addition, PG&E is authorized to refund certain customer deposits, use certain bank accounts and make cash collateral deposits, and assume responsibility for various hydroelectric contracts. PG&E also has received permission from the Bankruptcy Court to make payments on (1) pre- and post-petition interest on certain claims, (2) pre-petition secured debt that has matured, and (3) certain other vendors.

PG&E has agreed to pay pre- and post-petition interest on Liabilities Subject to Compromise at the rates set forth below.

	Amount Owed	Agreed Upon Interest Rate at June 30, 2003
	(in millions)	
Commercial Paper Claims	$ 873	7.841%
Floating Rate Notes	1,240	7.958%
Senior Notes	680	10.000%
Medium-Term Notes	287	6.185% to 8.825%
Revolving Line of Credit Claims	938	8.375%
QFs	56	5.000%
Other Claims	5,382	Various
Liabilities Subject to Compromise at June 30, 2003	$9,456	

As PG&E s original proposed plan of reorganization (see below) 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 set forth above reflect an increase of 37.5 basis points over the originally agreed upon rates, for periods on and after February 15, 2003. Since the original plan of reorganization (see below) will 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 March 15, 2004 will be increased by an additional 37.5 basis points. For other claims, PG&E has recorded interest at the contractual or FERC-tariffed interest rate. When those rates do not apply, PG&E has recorded interest at the federal judgment rate.

Competing Plans of Reorganization

In September 2001, PG&E Corporation and PG&E submitted a proposed plan of reorganization to the Bankruptcy Court (the original plan of reorganization) that proposed to disaggregate PG&E s current business

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

and to refinance the restructured businesses. In April 2002, the CPUC, later joined by the Official Committee of Unsecured Creditors (OCC), submitted an alternative proposed plan of reorganization with the Bankruptcy Court that did not provide for disaggregation of PG&E s business. In March 2003, the Bankruptcy Court stayed all proceedings relating to the confirmation trial for the competing plans to allow PG&E, the CPUC, and certain other parties to participate in a judicially supervised settlement conference in order to explore the possibility of resolving the differences between the competing plans of reorganization.

The Proposed Settlement Agreement

On June 19, 2003, PG&E Corporation, PG&E, and the staff of the CPUC announced a proposed settlement agreement that contemplates a new plan of reorganization (Settlement Plan) to supersede the competing plans of reorganization. Under the proposed settlement agreement, PG&E Corporation and PG&E would agree that they no longer would propose to disaggregate the historic businesses of PG&E as had been proposed in the original plan of reorganization. Instead, PG&E would remain a vertically integrated utility subject to the CPUC s jurisdiction.

The treatment of creditors under the Settlement Plan would be consistent with that provided in the original plan of reorganization, except that those creditors that were to receive long-term notes to be issued by the limited liability companies contemplated under the original plan of reorganization or a combination of cash and long-term notes would be paid entirely in cash. The Settlement Plan contemplates satisfaction of allowed claims in PG&E s Chapter 11 proceeding in cash from the issuance of approximately $8.7 billion in debt (which may be either secured or unsecured depending on market conditions at the time of issuance), cash on hand, or, in some cases, the reinstatement of the underlying debt. The actual amount of debt that PG&E would issue will depend upon how certain claims are resolved and the amount of cash on hand at the time the Settlement Plan becomes effective, as well as cash requirements related to closing out any interest rate hedges and whether all intended reinstated debt will be reinstated.

The proposed settlement agreement is subject to the approval of the Boards of Directors of PG&E Corporation and PG&E, as well as the CPUC. In addition, the proposed settlement agreement must be executed by all parties on or before December 31, 2003. The CPUC will conduct evidentiary hearings during September 2003 before deciding whether or not to approve the proposed settlement agreement. On July 25, 2003, PG&E filed its testimony in support of the proposed settlement agreement. Testimony from the staff of the CPUC and the OCC was also filed on July 25, 2003. The CPUC currently is expected to vote on the proposed settlement agreement on December 18, 2003.

In addition, the Bankruptcy Court must confirm the Settlement Plan. While the CPUC is not a proponent, it would agree under the proposed settlement agreement to support the Settlement Plan. On July 31, 2003, the Bankruptcy Court approved the disclosure statement that will be used to solicit approval of the Settlement Plan from creditors entitled to vote on the Settlement Plan. On August 1, 2003, the Bankruptcy Court approved the solicitation procedures and ordered that the solicitation period to start on August 15 and end on September 29, 2003. The Bankruptcy Court has ordered that the confirmation hearing begin on November 3, 2003, and that all objections to the Settlement Plan be filed by September 2, 2003.

Regulatory Assets

The proposed settlement agreement provides for a new regulatory asset (Regulatory Asset) to restore PG&E to financial health and to maintain and improve PG&E s financial health in the future. The Regulatory Asset would be a separate and additional part of PG&E s rate base of approximately $3.7 billion, pre-tax, included in non-current assets on PG&E s balance sheet. The Regulatory Asset would be amortized on a mortgage-style basis over nine years beginning January 1, 2004.

PG&E would continue to cooperate with the CPUC and the State of California in seeking refunds from power generators. The net after-tax amount of any refunds, claim offsets, or other credits from generators or other

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

energy suppliers relating to PG&E s power procurement costs that PG&E actually realizes in cash or by offset of creditor claims in its Chapter 11 proceeding would be applied to reduce the outstanding balance and the remaining amortization of the Regulatory Asset. Amounts received in cash by PG&E for electric claims under the master settlement agreement with El Paso Corporation and certain of its affiliates (El Paso) also would be included in such a reduction.

The Regulatory Asset would earn a return on equity (ROE) of at least 11.22 percent for the life of the Regulatory Asset. For 2004 and 2005, the common equity ratio of PG&E s capital structure would be the higher of forecast average equity ratio (in accordance with the 2003 cost of capital proceeding to be filed by PG&E for calendar year 2004 and the 2005 cost of capital proceeding, or such other CPUC proceedings as may be appropriate) or 48.60 percent. Once the common equity ratio of PG&E s capital structure reaches 52.00 percent, the authorized common equity ratio of the Regulatory Asset would be no less than 52.00 percent for the remaining life of the Regulatory Asset. The CPUC would use its usual method for tax-effecting the ROE component of the Regulatory Asset in establishing PG&E s revenue requirements for the Regulatory Asset. PG&E would record this regulatory asset when events that meet applicable accounting rules occur.

The CPUC would agree that PG&E s rate base for the utility retained generation (URG) would be deemed just and reasonable and would not be subject to modification, adjustment, or reduction, except as necessary to reflect capital expenditures and any change in authorized depreciation. This would result in the recording of an additional regulatory asset of approximately $1.3 billion, pre-tax, for the future recovery of generation-related assets that were charged to expense in 2000. The CPUC would not be precluded from determining the reasonableness of any capital expenditures made for URG after the effective date of the Settlement Plan. PG&E would record this regulatory asset when events that meet applicable accounting rules occur.

The CPUC would not reduce or impair the value of the Regulatory Asset or PG&E s rate base for its URG, by taking the Regulatory Asset or PG&E s rate base for its URG, or their amortization or earnings into account when setting other PG&E revenue requirements and resulting rates. The CPUC also would not take the settlement agreement or the Regulatory Asset into account in establishing PG&E s authorized ROE or capital structure.

Among other terms, the proposed settlement agreement also provides that:

Ratemaking Matters

The CPUC would maintain PG&E s retail electric rates at current levels through December 31, 2003. Beginning January 1, 2004, the CPUC may adjust PG&E s retail electric rates prospectively consistent with the proposed settlement agreement, the Settlement Plan, the order confirming the Settlement Plan, and California law. The proposed settlement agreement contemplates that retail electric rates would be reduced in January 2004, with further reductions expected thereafter.

The CPUC would set PG&E s capital structure and authorized ROE in PG&E s annual cost of capital proceedings in its usual manner and provided that from January 1, 2004, until Standard & Poor s (S&P) has issued a long-term issuer credit rating for PG&E of at least A- or Moody s Investors Services (Moody s) has issued an issuer credit rating for PG&E of at least A3, the authorized ROE would be no less than 11.22 percent per year and the authorized equity ratio for ratemaking purposes would be no less than 52.00 percent, except that for 2004 and 2005, the authorized equity ratio would equal the greater of the forecast average equity ratio in PG&E s cost of capital proceeding or 48.60 percent.

Balances in PG&E s Transition Cost Balancing Account (which tracks the amount of PG&E s under-collected transition and electricity procurement costs) as of the effective date of the Settlement Plan would have no further impact on PG&E s retail electric rates and would not be subject to further CPUC review except for verification of recorded balances.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

The CPUC would timely act upon PG&E s applications to collect in rates prudently incurred costs (including return of and return on) of any new and reasonable investment in utility plant and assets. The CPUC also would promptly adjust PG&E s rates consistent with California legislation (Assembly Bill (AB) 57 and Senate Bill (SB) 1976) and the CPUC-California Department of Water Resources (DWR) rate agreement to ensure that PG&E s collection of certain charges to service existing rate reduction bonds, regulatory asset amortization and return, and base revenue requirements (e.g., electricity and natural gas distribution, PG&E s rate base for its URG, gas commodity procurement, existing QF contract costs and associated return) are not impaired. The CPUC would not discriminate against PG&E because of PG&E s Chapter 11 case, PG&E s pending federal lawsuit against the CPUC Commissioners to recover its previously incurred costs of providing electric service from ratepayers under the federal filed rate doctrine, the settlement agreement, the Regulatory Asset, or any other matters addressed or resolved by the proposed settlement agreement.

PG&E would file an advice letter to implement all of the rate and tariff changes necessary to implement the Settlement Plan. The CPUC would act promptly on the advice filing and revised rates and tariffs. The CPUC also would act promptly on certain of PG&E s pending ratemaking proceedings, including PG&E s pending 2003 General Rate Case (GRC). The outcome of these proceedings may result in the establishment of additional regulatory assets on PG&E s Consolidated Balance Sheet.

California Department of Water Resources Contracts PG&E would agree to accept an assignment of or to assume legal and financial responsibility for the DWR contracts that have been allocated to PG&E, but only if (1) PG&E receives a long-term issuer credit rating of at least A from S&P and A2 from Moody s, after giving effect to such assignment or assumption, (2) the CPUC first has made a finding that the DWR contracts being assumed are just and reasonable, and (3) the CPUC has acted to ensure that PG&E receives full and timely rate recovery of all costs of the DWR contracts over their lives without further review. The CPUC would retain the right to review administration and dispatch of the DWR contracts consistent with applicable law.

Headroom Revenues The CPUC would agree and acknowledge that the headroom, surcharge, and base revenues accrued or collected by PG&E through and including December 31, 2003, are the property of PG&E s Chapter 11 estate, have been or will be used for utility purposes, including to pay creditors in PG&E s Chapter 11 proceeding, have been included in PG&E s retail electric rates consistent with state and federal law, and are not subject to refund. The proposed settlement defines headroom as PG&E s total net after-tax income reported under GAAP, less earnings from operations, (as has been historically defined by PG&E in its earnings press release, a non-GAAP financial measure), plus after-tax amounts accrued for Chapter 11-related administration and Chapter 11-related interest costs, all multiplied by 1.67, provided the calculation will reflect the outcome of PG&E s 2003 GRC. The proposed settlement agreement notes that it is in the public interest to restore PG&E s financial health and to allow PG&E to recover, over a reasonable time, prior uncollected costs. For financial reporting purposes, these amounts that restore PG&E s financial health and recover previously written-off under-collected costs are referred to as headroom. The proposed settlement agreement provides that if headroom revenues accrued by PG&E during 2003 are greater than $875 million, pre-tax, PG&E would refund the excess to ratepayers. Further, if headroom revenues are less than $775 million, pre-tax, the CPUC would allow PG&E to collect the shortfall in rates. Headroom revenues for the six months ended June 30, 2003, were $237 million, pre-tax, as calculated under the terms of the proposed settlement agreement.

Dismissal of Filed Rate Case, Other Litigation, and Regulatory Proceedings On or as soon as practicable after the later of the effective date of the Settlement Plan or the date the CPUC decision approving the proposed settlement agreement no longer is subject to appeal, PG&E would dismiss with prejudice its filed rate case and withdraw the original plan of reorganization. In addition, the CPUC would resolve phase 2 of the pending Annual Transition Cost Proceeding in which the CPUC is reviewing the reasonableness of PG&E s procurement costs incurred during the energy crisis with no adverse impact on PG&E s cost recovery as filed.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

Fees and Expenses The proposed settlement agreement would require PG&E to reimburse PG&E Corporation and the CPUC after the date the Settlement Plan is confirmed for all of their respective professional fees and expenses incurred in connection with the Chapter 11 proceeding. Of such amounts, the amounts reimbursed to the CPUC could be recovered from ratepayers. As of June 30, 2003, PG&E Corporation had incurred expenses of approximately $121 million on PG&E s Chapter 11 proceeding.

Environmental Measures PG&E would implement three environmental enhancement measures:

PG&E would encumber with conservation easements or donate approximately 140,000 acres of specific watershed and other land to public agencies or non-profit conservation organizations;

PG&E would establish a California non-profit corporation to oversee the environmental enhancements associated with these lands and fund such corporation over ten years with $70 million, although it would be entitled to recover these payments in rates without further review; and

PG&E would create a non-profit corporation funded by shareholders with $15 million over five years dedicated to support research and investment in clean energy technology, primarily in PG&E s service territory.

Term The proposed settlement agreement generally would terminate nine years after the effective date of the Settlement Plan, except that all vested rights of the parties under the proposed settlement agreement would survive termination for the purpose of enforcement.

The Settlement Plan provides that it would not be confirmed by the Bankruptcy Court unless and until the following conditions are satisfied or waived:

The Bankruptcy Court enters an order or orders:

Approving the Settlement Plan, authorizing PG&E to execute, enter into and deliver the Settlement Plan, and to execute, implement and take all actions necessary or appropriate to give effect to the transactions contemplated by the Settlement Plan;

Approving and authorizing the execution of, and finding reasonable the terms and conditions of, the proposed settlement agreement; and

The confirmation order is, in form and substance, reasonably satisfactory to PG&E Corporation, PG&E, the OCC and the CPUC and specifically includes certain matters.

The Settlement Plan also provides that it would not become effective unless and until the following conditions are satisfied or waived:

The effective date occurs on or before March 31, 2004;

All actions, documents and agreements necessary to implement the Settlement Plan are effected or executed;

PG&E Corporation and PG&E have received all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions or documents deemed necessary to implement the Settlement Plan;

The Settlement Plan has not been modified in a material way since the date of confirmation;

PG&E has consummated the sale of the notes contemplated by the Settlement Plan;

S&P has issued a long-term issuer credit rating for PG&E of not less than BBB- and Moody s has issued an issuer rating for PG&E of not less than Baa3;

S&P and Moody s have issued credit ratings for the notes to be offered by PG&E of not less than BBB- and Baa3, respectively;

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

The CPUC has given final nonappealable approval of the proposed settlement agreement;

Each of the parties to the proposed settlement agreement has executed and delivered the settlement agreement;

The CPUC has given final nonappealable approval for all of the financings, securities and accounts receivable programs provided for in the Settlement Plan; and

The CPUC has given final nonappealable approval for all rates, tariffs and agreements necessary to implement the Settlement Plan.

The last six conditions cannot be waived, except that PG&E Corporation and PG&E can waive the right to the finality provisions regarding CPUC approvals.

PG&E is unable to predict whether and when the proposed settlement agreement will become effective or whether the Settlement Plan will be confirmed or implemented. If the Settlement Plan is not confirmed, or if the CPUC does not approve the proposed settlement agreement and related rates, or if the CPUC takes actions materially inconsistent with the proposed settlement agreement in pending regulatory proceedings associated with the recovery of transition costs and surcharge revenues, or the allocation of DWR electricity to customers of IOUs, as detailed in Note 4 below, then PG&E s financial condition and results of operations could be materially adversely affected. The settlement agreement and Settlement Plan may also be affected by the outcome of the California Supreme Court s consideration of questions certified to it by the Ninth Circuit regarding the validity of a settlement agreement between the CPUC and another California IOU, Southern California Edison Company (SCE). Several entities, including The Utility Reform Network (TURN) challenged the SCE settlement. Oral argument occurred before the California Supreme Court on May 27, 2003, and it is expected that the Court will issue a ruling by August 27, 2003. PG&E believes that, even if the California Supreme Court finds the SCE settlement violates state law, there are independent legal and factual reasons under which the proposed settlement agreement and the Settlement Plan would still be valid under state and federal law. The effectiveness of the Settlement Plan is not conditioned upon receiving a favorable ruling in the SCE case by the California Supreme Court.

Note 3: Price Risk Management

PG&E s ineffective portion of changes in amounts of cash flow hedges was immaterial for the three and six months ended June 30, 2003, and June 30, 2002.

Price Risk Management Assets and Liabilities

At June 30, 2003, PG&E had cash flow hedges associated with natural gas commodity price risk. These contracts are presented at fair value on the accompanying PG&E Condensed Consolidated Balances Sheets and the accompanying PG&E Consolidated Balance Sheets reflect the aggregation of outstanding contracts. These fair values, amounting to $11 million at June 30, 2003, are calculated on a mark-to-market basis. At June 30, 2002, PG&E did not have any cash flow hedges.

PG&E has certain non-trading contracts that are exempt from SFAS No. 133 under the normal purchases and sales exemption. Additionally, PG&E has certain other non-trading derivative contracts that do not qualify for cash flow hedge accounting or the normal purchase and sales exemption to SFAS No. 133. These derivatives are reported in earnings on a mark-to-market basis.

Credit Risk

Credit risk is the risk of loss that PG&E 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 on the Consolidated Balance Sheets of PG&E. PG&E conducts business

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

primarily with customers or vendors, referred to as counterparties, in the energy industry. These counterparties include other IOUs, 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 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 manages its credit risk in accordance with the PG&E Corporation Risk Management Policy. This established processes for assigning credit limits to counterparties before entering into agreements with significant exposure to PG&E. 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 takes immediate action to reduce the exposure, or obtain additional collateral, or both. Further, PG&E relies 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 calculates 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.

During the six-month period ended June 30, 2003, PG&E s credit risk decreased, as compared to December 31, 2002, primarily due to the receipt of payment from a previously terminated contract with a counterparty.

During the six-month period ended June 30, 2003, PG&E recognized no losses due to the contract defaults or bankruptcies of counterparties.

At June 30, 2003, PG&E had one investment grade counterparty that represented 17 percent of its net credit exposure and one below-investment grade counterparty that represented 11 percent of its net credit exposure.

The PG&E 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 s credit risk exposure to counterparties with a greater than 10 percent net credit exposure were as follows:

	Gross Credit Exposure Before Credit Collateral(1)	Credit Collateral	Net Credit Exposure(2)	Number of Counterparties >10 percent	Net Exposure of Counterparties >10 percent
			(in millions)		
At June 30, 2003(3)	$220	$ 55	$165	2	$ 46
At December 31, 2002 (3)	$288	$113	$175	2	$ 55

(1) Gross credit exposure equals mark-to-market value, 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, model, or credit reserves.

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

(3) PG&E s gross credit exposure includes wholesale activity only. Retail activity and payables incurred prior to PG&E s Chapter 11 filing are not included. Retail activity at PG&E consists of the accounts receivable from the sale of gas and electricity to millions of residential and small commercial customers.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

The schedule below summarizes the credit quality of PG&E s net credit risk exposure to counterparties at June 30, 2003, and December 31, 2002.

Credit Quality(1)	Net Credit Exposure(2)	Percentage of Net Credit Exposure
	(in millions)	
At June 30, 2003		
Investment grade(3)(4)	$ 101	61%
Noninvestment grade	64	39%
Not rated(4)		
Total	$ 165	100%
At December 31, 2002		
Investment grade(3)(4)	$ 111	63%
Noninvestment grade	64	37%
Not rated(4)		
Total	$ 175	100%

(1) Credit ratings are determined by using publicly available credit ratings of the counterparty. If the counterparty provides a guarantee by a higher rated entity (e.g., its parent), the rating determination is based on the rating of its guarantor.

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

(3) Investment grade is determined using publicly available information, i.e., rated at least Baa3 by Moody s and BBB- by S&P.

(4) Most counterparties with no ratings are governmental authorities that are not rated through publicly available information, but which PG&E has assessed as equivalent to investment grade based upon an internal assessment of credit quality. These are designated as investment grade in the above. Other counterparties with no rating obtainable through publicly available information, are designated as not rated above, but are subject to an internal assessment of their credit quality and an internal credit rating designation.

PG&E 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. At June 30, 2003, PG&E had a net regional concentration of credit exposure totaling $165 million to counterparties that conduct business primarily throughout North America.

Note 4: Commitments and Contingencies

PG&E has substantial financial commitments and contingencies in connection with agreements entered into supporting its operating activities. These commitments are discussed more fully in the Notes to the Consolidated Financial Statements for the years ended December 31, 2002, 2001 and 2000 included in this Prospectus. The following summarizes PG&E s material contingencies as of June 30, 2003, and canceled, new, and significantly modified commitments since December 31, 2002.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

Commitments

Natural Gas Supply and Transportation Commitments PG&E purchases natural gas directly from producers and marketers in both Canada and the United States. The composition of the portfolio of natural gas procurement contracts has fluctuated, generally based on market conditions.

PG&E also has long-term gas transportation service agreements with various Canadian and interstate pipeline companies. These companies are responsible for transporting PG&E s gas to the California border. The total demand charges that PG&E will pay each year may change due to changes in tariff rates. These agreements include provisions for payment of fixed demand charges for reserving firm pipeline capacity as well as volumetric transportation charges.

At June 30, 2003, PG&E s obligations for natural gas purchases and gas transportation services were as follows:

	(in millions)
2003	$479
2004	276
2005	84
2006	26
2007	7
Thereafter	
Total	$872

Since PG&E is in Chapter 11 and its credit ratings are below investment grade, PG&E uses several different credit arrangements for the purpose of purchasing natural gas. PG&E has a $10 million standby letter of credit and has pledged its gas customer accounts receivable. The core gas inventory may be pledged but only if PG&E s gas customer accounts receivable are less than the amount that PG&E owes to the gas suppliers. Through June 30, 2003, the accounts receivable pledge has been sufficient. The CPUC authorized PG&E to pledge its gas accounts receivable and core inventory, if necessary, until the earlier of:

May 1, 2004;

15 days after an upgrade of the credit rating of PG&E s mortgage bonds to at least BBB- by S&P or Baa3 by Moody s;

The effective date of a plan of reorganization; or

The dismissal or conversion of PG&E s Chapter 11 proceeding.

At June 30, 2003, the pledged amount of gas accounts receivable was $220 million.

Transmission Control Agreement PG&E entered into a Transmission Control Agreement (TCA) with the ISO and others. As a transmission owner, PG&E is required to give two years notice if it wishes to withdraw from the TCA. Under this agreement, the transmission owners, which also include SCE and San Diego Gas & Electric Company, assign control and operation of their electric transmission systems to the ISO. In addition, as a party to the TCA, the transmission owners are responsible for the costs of the Reliability Must-Run (RMR) Agreements between the ISO and owners of the plants subject to RMR contracts (RMR plants). Under the RMR Agreements, RMR plants must remain available to generate electricity when needed for transmission system reliability upon the ISO s demand.

At June 30, 2003, the ISO has RMR agreements that obligate PG&E for approximately $911 million during the period July 1, 2003, to June 30, 2005.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

It is possible that PG&E may receive a refund of RMR costs previously paid to the ISO. In June 2000, an Administrative Law Judge (ALJ) at the FERC issued an initial decision that would require the subsidiaries of the Mirant Corporation (Mirant) that are parties to three RMR contracts with the ISO to refund to the ISO, and the ISO to refund to PG&E, excess payments for availability of Mirant s generating units under the RMR contracts. If the FERC were to affirm the ALJ s initial decision, PG&E would expect refunds, with interest, of approximately $300 million. Any refunds received would be used to reduce previously under-collected transition and procurement costs or to lower future reliability services rates depending on the time period covered by the refunds. On July 14, 2003, Mirant filed a petition for reorganization under Chapter 11 of the Bankruptcy Code. PG&E is unable to predict at this time when the FERC will issue a final decision on this issue, what the outcome of the FERC s decision will be, and the amount of any refunds, which may be impacted by Mirant s Chapter 11 filing, PG&E will ultimately receive.

Electricity Purchases to Meet Demand On January 1, 2003, PG&E resumed the function of procuring electricity to meet the portion of its customers needs that is not covered by the combination of the allocation of electricity from existing DWR contracts and its own electric generation resources and contracts. To meet this requirement, PG&E entered into contracts for fuel supply, capacity, and transmission rights. In order to enter into these contracts, PG&E has posted collateral with the California ISO and several other counterparties. These contracts, with terms of one year or less, did not have a material impact on PG&E s commitments previously disclosed in its Notes to the Consolidated Financial Statements for the years ended December 31, 2002, 2001 and 2000, included in this Prospectus.

In June 2003, the CPUC issued a decision that requires each IOU to increase procurement of renewable energy by at least 1 percent per year. By the end of 2017, each IOU must be procuring at least 20 percent of its total electricity from renewable resources. The decision states that PG&E is not obligated to procure additional renewable energy until it is creditworthy and that PG&E will accumulate an Annual Procurement Target (APT) based on 1 percent of retail sales, each year, starting in 2003, until it receives an investment grade credit rating. When PG&E receives an investment grade credit rating it will be required to enter into procurement contracts for renewable energy to meet its accumulated APT. Although PG&E cannot predict what the terms, including price, of such contracts would be, the decision requires that the procurement price under such contracts be at or below a market price benchmark established by the CPUC after the bids have been received. If PG&E exceeds its APT, it can apply the excess to meet the APT in future years. For under-procurement, the decision allows IOUs to carry over an annual deficit of 25 percent to the next three years without explanation. Failure to meet minimum APTs without prior CPUC approval would result in an automatic penalty of $0.05 per kilowatt-hour (kWh), subject to an annual penalty cap of $25 million.

Contingencies

PG&E has significant gain and loss contingencies as discussed below.

Recovery of Transition Costs and Surcharge Revenues As a result of frozen rates, at December 31, 2000, PG&E had accumulated a total of approximately $4.1 billion, after-tax, in under-collected purchased power and generation-related transition costs. This amount was charged to earnings at that time because PG&E could no longer conclude that such costs were probable of collection through regulated rates. In 2001 and 2002, as a result of stabilized wholesale electricity prices and the CPUC-authorized surcharges discussed below, PG&E s total generation-related electric revenues were greater than its generation-related costs, resulting in the partial recovery of under-collected purchased power and generation-related transition costs that were previously written off. As of December 31, 2002, the outstanding balance of the under-collected purchased power and generation-related transition costs was $2.2 billion, after-tax. During the first quarter of 2003, generation-related costs exceeded generation-related revenues due to lower winter consumption and lower winter rates. During the second quarter of 2003, generation-related revenues returned to levels in excess of generation-related costs. As of June 30, 2003, the outstanding balance of PG&E s under-collected purchased power and generation-related transition costs amounted to $2.1 billion, after-tax, excluding interest and other Chapter 11-related costs.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

Generation-related costs in excess of generation-related revenues continue to be expensed as they are incurred. Under the proposed settlement agreement in PG&E s Chapter 11 proceeding, the CPUC would agree to establish a new regulatory asset to restore PG&E to financial health (see Note 2). The balances in PG&E s transition cost balancing account as of January 1, 2004, would have no further impact on PG&E s retail electric rates and would be subject to no further review by the CPUC except for verification of recorded balances.

In January 2001, the CPUC increased electric rates by $0.01 per kWh, in March 2001 by another $0.03 per kWh, and in May 2001 by an additional $0.005 per kWh. The use of these surcharge revenues was restricted to ongoing procurement costs and future power purchases. In November and December 2002, the CPUC approved decisions modifying the restrictions on the use of revenues generated by the surcharges and authorizing PG&E to record amounts related to the surcharge revenues as an offset to unrecovered transition costs. Based on these CPUC decisions and an agreement between the CPUC and another IOU, SCE, in which SCE was allowed to use its $0.005 per kWh surcharge to offset its DWR revenue requirement, PG&E has continued to recognize revenues related to the $0.01, $0.03, and $0.005 surcharges after the statutory end of the retail electric rate freeze, which was March 31, 2002, even without considering the proposed settlement agreement in PG&E s Chapter 11 proceeding (discussed in Note 2). As such, PG&E has not recorded a regulatory liability or a refund reserve for these surcharge revenues, or any portion thereof, in its financial statements. From January 2001 to June 30, 2003, PG&E recognized total surcharge revenues of $6.5 billion, pre-tax.

Under the proposed settlement agreement discussed in Note 2, the CPUC would agree and acknowledge that the headroom, surcharge, and base revenues accrued or collected by PG&E through and including December 31, 2003, are the property of PG&E s Chapter 11 estate, have been or will be used for utility purposes, including to pay creditors in PG&E s Chapter 11 proceeding, have been included in PG&E s retail electric rates consistent with state and federal law, and are not subject to refund. The proposed settlement defines headroom as PG&E s total net after-tax income reported under GAAP, less earnings from operations, (as has been historically defined by PG&E Corporation in its earnings press release, a non-GAAP financial measure), plus after-tax amounts accrued for Chapter 11-related administration and Chapter 11-related interest costs, all multiplied by 1.67, provided the calculation will reflect the outcome of PG&E s 2003 GRC. The proposed settlement agreement notes that it is in the public interest to restore PG&E s financial health and to allow PG&E to recover, over a reasonable time, prior uncollected costs. For financial reporting purposes, these amounts that restore PG&E s financial health and recover previously written-off under-collected costs are referred to as headroom. The proposed settlement agreement provides that if headroom revenues accrued by PG&E during 2003 are greater than $875 million, pre-tax, it would refund the excess to ratepayers. Further, if headroom revenues are less than $775 million, pre-tax, the CPUC would allow PG&E to collect the shortfall in rates. Headroom revenues for the six months ended June 30, 2003, were $237 million, pre-tax, as calculated under the terms of the proposed settlement agreement.

PG&E s ultimate recovery of its previously written-off under-collected purchased power and generation-related transition costs if the proposed settlement agreement and Settlement Plan are not implemented and the validity of the CPUC s agreements under the proposed settlement agreement regarding headroom, surcharge and base revenues collected by PG&E through and including December 31, 2003, may depend upon the California Supreme Court s consideration of questions certified to it by the Ninth Circuit regarding the legality of recovery of under-collected costs by SCE under a settlement and stipulated federal court judgment with the CPUC. The CPUC represented to the court that, in part, as a result of California AB 6X, which prevented PG&E from divesting generation assets, it has the authority to allow PG&E and SCE to recover under-collected purchased power and generation-related transition costs beyond the end of the rate freeze. The settlement reached by the CPUC and SCE provides that the CPUC would maintain SCE s rates at their current levels (beyond the end of the rate freeze) until the earlier of the date that SCE recovered its transition costs or December 31, 2003. Several entities, including TURN, have challenged this settlement and the ratemaking adopted by the CPUC to implement the settlement, arguing, among other things, that the recovery of SCE s under-collected costs in retail rates under the settlement violates the provisions of AB 1890 prohibiting post-freeze recovery of transition and

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

procurement costs. Oral argument occurred before the California Supreme Court on May 27, 2003, and it is expected that the Court will issue a ruling by August 27, 2003.

Even if the California Supreme Court were to rule that the SCE settlement violates state law and, therefore, California IOUs are not permitted to recover their procurement and transition costs after the end of the rate freeze, such a ruling would not affect PG&E s claim that it has a right to recover such costs under the federal filed rate doctrine, which is currently pending before the federal courts. Under the proposed settlement agreement, on or as soon as practicable after the latter of the effective date of the Settlement Plan or the date that CPUC approval of the proposed settlement agreement is no longer subject to appeal, PG&E would dismiss with prejudice the filed rate case.

Further, PG&E believes that, even if the California Supreme Court finds the SCE settlement violates state law, there are independent legal and factual reasons under which the proposed settlement agreement and the Settlement Plan would still be valid under state and federal law. The effectiveness of the Settlement Plan is not conditioned on receiving a favorable ruling in the SCE case by the California Supreme Court.

If the Settlement Plan contemplated in the proposed settlement agreement in PG&E s Chapter 11 proceeding is not implemented, it is possible that at some future date the CPUC, either in response to certain judicial decisions, or on its own initiative, may change its interpretation of law or otherwise seek to change PG&E s overall retail electric rates retroactively. As stated above, PG&E has not provided reserves for potential refunds of any of these surcharge revenues as of June 30, 2003. If the CPUC requires PG&E to refund any of these revenues in the future, its earnings could be materially affected.

In July 2003, a CPUC Commissioner issued a proposed decision that proposes to find that the retail electric rate freeze ended on January 18, 2001. The proposed decision also provides that the CPUC would determine the extent and disposition of costs previously defined as uneconomic, transition or stranded, in a separate proceeding. The proposed decision contemplates that the separate proceeding would also determine whether the recovery of these costs has been fully addressed or resolved in PG&E s Chapter 11 proceeding or in other CPUC proceedings. PG&E has filed comments suggesting that the CPUC defer its decision on these issues pending the CPUC s consideration of the proposed settlement agreement and the implementation of the Settlement Plan. PG&E cannot predict the ultimate outcome of this proceeding.

Allocation of DWR Electricity to Customers of the IOUs 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 PG&E, 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 respective resource portfolios by January 1, 2003. The DWR retains legal and financial responsibility for these contracts.

Under the proposed settlement agreement, PG&E would agree to accept an assignment of or to assume legal and financial responsibility for the DWR contracts only if (1) PG&E receives a long-term issuer credit rating of at least A from S&P and an issuer credit rating of at least A2 from Moody s after giving effect to such assignment or assumption, (2) the CPUC first makes a finding that the DWR allocated contracts are just and reasonable, and (3) the CPUC first acts to ensure that PG&E receives full and timely rate recovery of all costs of the DWR contracts over their life without further review. The CPUC would retain the right to review administration and dispatch of the DWR contracts consistent with applicable law. The State of California has stated publicly that it does not intend to transfer full legal title of, and responsibility for, the DWR electricity contracts to the IOUs until they are in a position where they will be financially able to absorb the contracts. However, if the proposed settlement agreement is not approved and either the State of California or the CPUC grants the DWR the authority to transfer legal title of the DWR contracts to PG&E without having first met PG&E s conditions, PG&E s results of operations could be adversely affected.

Nuclear Insurance PG&E has several types of nuclear insurance for its Diablo Canyon Power Plant (Diablo Canyon) and Humboldt Bay Power Plant (Humboldt Bay). PG&E has insurance coverage for property

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

damages and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). NEIL is a mutual insurer owned by utilities with nuclear facilities. Under this insurance, if any nuclear generating facility insured by NEIL suffers severe losses, the NEIL Board of Directors could require PG&E to pay additional annual premiums of up to $32 million for Diablo Canyon to cover property damages and business interruption and up to $1.4 million for Humboldt Bay to cover property damages.

Under federal law, the Price-Anderson Act (Act), public liability claims from a nuclear incident are limited to $9.5 billion. As required by the Act, PG&E has purchased the maximum available public liability insurance of $300 million for Diablo Canyon. The balance of the $9.5 billion of liability protection is covered by a loss-sharing program (secondary financial protection) among utilities owning nuclear reactors. Under the Act, secondary financial protection is required for all reactors of 100 megawatts (MW) or higher. If a nuclear incident results in costs in excess of $300 million, then PG&E may be responsible for up to $88 million per reactor, with payments in each year limited to a maximum of $10 million per incident until PG&E has fully paid its share of the liability. Since PG&E has two nuclear reactors of over 100 MW, PG&E may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident. In February 2003, a provision extending the Act through the end of 2003 was adopted by the U.S. Congress. No other material terms of the Act changed as a result of the provision.

Additionally, PG&E has purchased $53.3 million of private liability insurance for Humboldt Bay and has a $500 million indemnification from the Nuclear Regulatory Commission for public liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of private liability insurance for Humboldt Bay.

Workers Compensation Security PG&E is self-insured for workers compensation. PG&E must deposit collateral with the State Department of Industrial Relations (DIR) to maintain its status as a self-insurer for workers compensation claims made against PG&E. Acceptable forms of collateral include surety bonds, letters of credit, cash, or securities PG&E currently provides collateral in the form of approximately $365 million in surety bonds.

In February 2001, several surety companies provided cancellation notices because of PG&E s financial situation. The DIR has not agreed to release the canceling sureties from their obligations for claims occurring prior to the cancellation and has continued to apply the canceled bond amounts, totaling $185 million, towards the $365 million amount of collateral. Three additional active surety bonds totaling $180 million make up PG&E s collateral. At June 30, 2003, the canceled bonds have not impacted PG&E s self-insured status under California law. PG&E Corporation has guaranteed PG&E s reimbursement obligation associated with these surety bonds and PG&E s underlying obligation to pay workers compensation claims.

Balancing Account Reserves In 2002, the CPUC ordered PG&E to create certain electric balancing accounts to track specific electric-related amounts, including revenue shortfalls from baseline allowance increases and costs related to the self-generation incentive program, for which the CPUC has not yet determined a specific recovery method. 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 PG&E cannot conclude that the amounts in these balancing accounts are considered probable of recovery in future rates, PG&E has reserved these balances by recording a charge against earnings. As of June 30, 2003, the reserve associated with these balancing accounts was approximately $220 million.

DWR Revenue Requirement Because PG&E acts as a billing and collection agent for the DWR, amounts collected on behalf of the DWR (related to its revenue requirement) are excluded from PG&E s revenues. Until the CPUC modifies the current frozen rate structure or until the approval of the proposed settlement agreement and new rates under that settlement are implemented, changes to the DWR s 2001, 2002, or 2003 revenue requirement may materially affect PG&E s future earnings.

In December 2002, the CPUC issued a decision allocating approximately $2 billion of the DWR s 2003 $4.5 billion total statewide power charge-related revenue requirement to PG&E s customers. This revenue

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

requirement includes the cost associated with the DWR contracts allocated to PG&E s customers effective January 1, 2003. In April 2003, PG&E and the DWR entered into a CPUC-approved operating agreement that supersedes the December 2002 operating order. (The December 2002 operating order required PG&E to perform the operational, dispatch, and administrative functions for the DWR s allocated contracts beginning on January 1, 2003.) The operating agreement provides that PG&E will begin passing through additional revenues to the DWR consistent with the DWR s October 2002 and March 2003 requests for amendments to the formula that determines the amount of remittances to the DWR contained in the May 2002 servicing order but subject to the outcome of the CPUC s consideration of the DWR s requests. As of June 30, 2003, PG&E had accrued an additional $516 million, pre-tax, obligation for pass-through revenues to the DWR. PG&E had accrued $369 million, pre-tax, at December 31, 2002, and $539 million, pre-tax, at March 31, 2003 for these additional pass-through revenues to the DWR. During the second quarter of 2003, PG&E remitted $74 million of these pass-through revenues to the DWR and accrued an additional $51 million. The ultimate remittance of the $516 million amount accrued as of June 30, 2003, depends upon whether the CPUC grants the DWR s request for changes to the May 2002 servicing order (which was revised in December 2002) and whether such changes would be retroactive to January 2001, the date that the DWR began purchasing power for PG&E s customers.

In July 2003, the DWR submitted a supplemental 2003 revenue requirement to the CPUC reducing the amount of the total 2003 statewide power charge-related revenue the DWR was anticipating to receive by approximately $1 billion. The CPUC is responsible for determining how to allocate the reduced revenue requirement among the customers of the three California IOUs. The requested reduction expressly assumes that PG&E would remit an additional estimated cash payment of $539 million, which was accrued as of March 31, 2003, to the DWR in 2003. The ALJ in this proceeding indicated that the $539 million assumed remittance amount is an estimate and not a final number. The ALJ also indicated that, in connection with the proposed 2003 DWR revenue requirement reduction, the CPUC may consider reducing utility rates overall in order to pass through the savings to customers. The CPUC expects to consider a proposed decision during the third quarter of 2003. On August 1, 2003, another CPUC ALJ issued a draft decision that, if approved by the CPUC, would modify the May 2002 and December 2002 DWR servicing orders to require PG&E to remit an additional cash payment to the DWR for the period retroactive to January 2001 as discussed above. The draft decision would not specify the amount to be remitted but instead defers the issue to the 2003 DWR supplemental revenue requirement proceeding, where offsetting reductions to the DWR s revenue requirements and remittances for 2003 are being considered. The draft decision would not determine whether PG&E should pay interest on the additional payment, but would defer to both the DWR and PG&E to resolve the issue, subject to CPUC determination if the parties cannot agree. The draft decision is subject to comment by parties before being considered by the CPUC. A separate proceeding will consider a revision or adjustment for the revenue requirements remitted to the DWR for 2002 and 2001 costs. At that time, the CPUC may also consider a revision or adjustment to the allocation of the DWR s 2003 revenue requirement. PG&E cannot predict the ultimate outcome of this matter.

PG&E has a lawsuit pending in a California court, asking that the DWR be precluded from imposing its revenue requirements on PG&E and its customers until the DWR can demonstrate that its revenue requirements are just and reasonable, as legally required. The lawsuit is scheduled to be considered by the court during the third or fourth quarter of 2003.

Environmental Matters PG&E may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by PG&E for the storage, recycling, or disposal of potentially hazardous materials. Under federal and California laws, PG&E may be responsible for remediation of hazardous substances even if PG&E did not deposit those substances on the site.

PG&E records an environmental remediation liability when site assessments indicate remediation is probable and a range of likely clean-up costs can be reasonably estimated. PG&E reviews its remediation liability

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

on a quarterly basis for each site that may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure using (1) current technology, (2) enacted laws and regulations, (3) experience gained at similar sites, and (4) the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, PG&E records the lower end of this range.

PG&E had an undiscounted environmental remediation liability of $302 million at June 30, 2003, and $331 million at December 31, 2002. During the first half of the year, the liability was reduced by $29 million primarily due to a reassessment of the estimated cost of remediation. The $302 million accrued at June 30, 2003, included (1) $105 million related to the pre-closing remediation liability associated with divested generation facilities, and (2) $197 million related to remediation costs for those generation facilities that PG&E still owns, gas gathering sites, compressor stations, and manufactured gas plant sites that are either owned by PG&E or are the subject of remediation orders by environmental agencies or claims by the current owners of the former gas plant sites. Of the $302 million environmental remediation liability, PG&E has recovered $155 million through rates charged to its customers, and expects to recover approximately $93 million of the balance in future rates. Any amounts collected in excess of PG&E s ultimate obligations may be subject to refunds to ratepayers. PG&E also is recovering its costs from insurance carriers and from other third parties whenever it is possible.

The cost of the hazardous substance remediation ultimately undertaken by PG&E is difficult to estimate. The estimate depends on a number of uncertainties, including PG&E s responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. PG&E estimates the upper limit of the range using assumptions least favorable to PG&E, which is based upon a range of reasonably possible outcomes. PG&E s future costs could increase to as much as $418 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) PG&E is found to be responsible for clean-up costs at additional sites.

On June 28, 2001, the Bankruptcy Court authorized PG&E to continue its hazardous waste remediation program and to expend (1) up to $22 million in hazardous substance remediation programs and procedures in each calendar year in which the Chapter 11 case is pending, and (2) any additional amounts in emergency situations involving post-petition releases or threatened releases of hazardous substances subject to the Bankruptcy Court s specific approval.

The California Attorney General, on behalf of various state environmental agencies, filed claims in PG&E s Chapter 11 proceeding for environmental remediation at numerous sites totaling approximately $770 million. For most of these sites, remediation is ongoing in the normal course of business or PG&E is in the process of remediation in cooperation with the relevant agencies and other parties responsible for contributing to the clean-up. Since PG&E s proposed plan of reorganization provides that PG&E intends to respond to these types of claims in the regular course of business, and since PG&E has not argued that the Chapter 11 proceeding relieves it of its obligations to respond to valid environmental remediation orders, PG&E believes the state s claims seeking specific cash recoveries are unenforceable.

Moss Landing In December 1999, PG&E was notified by the purchaser of its former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water and organic debris from the intake, and that this procedure is not specified in the plant s National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). A settlement has been reached with the Central Coast Board, under which PG&E would pay a total of $5 million to be used for environmental projects. No civil penalties would be paid under the settlement. The Central Coast Board voted to accept the settlement in December 2002, and PG&E has obtained authorization from the Bankruptcy Court to enter into the final settlement agreement. The parties have signed the settlement agreement, which was incorporated into a consent decree entered in the California Superior Court on May 9, 2003. The California Attorney General has filed a claim in PG&E s Chapter 11 case to preserve the Central Coast Board s claim. PG&E currently is seeking withdrawal of this claim.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

PG&E believes the ultimate outcome of this matter will not have a material impact on its consolidated financial position of results of operations.

Diablo Canyon PG&E s Diablo Canyon employs a once-through cooling water system, which is regulated under a NPDES permit issued by the Central Coast Board. This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft Cease and Desist Order alleging that, although the temperature limit has never been exceeded, Diablo Canyon s discharge was not protective of beneficial uses.

In October 2000, the Central Coast Board and PG&E reached a tentative settlement of this matter pursuant to which the Central Coast Board agreed to find that its discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology reflects the best technology available under Section 316(b) of the Federal Clean Water Act. As part of the settlement, PG&E will take measures to preserve certain acreage north of the plant and will fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement. On May 5, 2003, the Bankruptcy Court authorized PG&E to sign the final settlement agreement. On June 17, 2003, the settlement was fully executed by PG&E , the Central Coast Board, and the California s Attorney General s Office. In order for the settlement to become effective, among other things, the Central Coast Board must renew Diablo Canyon s NPDES permit. However, at its July 10, 2003, meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement accepted in March 2003 and the Central Coast Board requested its staff to develop additional information on possible mitigation measures.

The California Attorney General has filed a claim in PG&E s Chapter 11 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. PG&E is seeking withdrawal of this claim.

PG&E believes the ultimate outcome of this matter will not have a material impact on its consolidated financial position or results of operations.

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

PG&E emits varying quantities of greenhouse gases, including carbon dioxide and methane, in the course of its operations. Depending on the ultimate regulatory regime put into place for greenhouse gases, PG&E 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 PG&E s financial condition or result of operations.

PG&E is 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.

Recorded Liability for Legal Matters In accordance with SFAS No. 5, Accounting for Contingencies, PG&E makes a provision for a liability when it is both probable that a liability has been incurred and the amount

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

of the loss can be reasonably estimated. These provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular case.

The provision for legal matters is included in PG&E s Other Noncurrent Liabilities in the Consolidated Balance Sheets, and totaled $219 million at June 30, 2003, and $202 million at December 31, 2002.

Legal Matters

In the normal course of business, PG&E is named in a number of claims and lawsuits. The most significant of these are discussed below. PG&E s Chapter 11 filing on April 6, 2001, discussed in Note 2, automatically stayed the litigation described below against PG&E, except as otherwise noted.

Chromium Litigation

There are 14 civil suits pending against PG&E in several California state courts. One of these suits also names PG&E Corporation as a defendant. Currently, there are approximately 1,200 plaintiffs in the chromium litigation cases. Approximately 1,260 individuals have filed proofs of claims with the Bankruptcy Court, most of whom are plaintiffs in the 14 chromium litigation cases. Approximately 1,035 of these claimants have filed proofs of claim requesting an approximate aggregate amount of $580 million and approximately another 225 claimants have filed claims for an unknown amount.

In general, plaintiffs and claimants allege that exposure to chromium at or near PG&E s compressor stations at Hinkley and Kettleman, California, and the area of California near Topock, Arizona, caused personal injuries, wrongful death, or other injury and seek related damages. The Bankruptcy Court has granted certain claimants motion for relief from stay so that the state court lawsuits pending before PG&E s Chapter 11 filing can proceed.

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

PG&E has filed 13 summary judgment motions challenging the claims of the trial test plaintiffs and four of the 13 summary judgment motions are scheduled for hearing in 2003. At a status conference on March 17, 2003, the Los Angeles Superior Court scheduled a trial of 18 test cases to commence in March 2004.

PG&E has recorded a reserve in its financial statements in the amount of $160 million for these matters. PG&E believes that, after taking into account the reserves recorded at June 30, 2003, the ultimate outcome of this matter will not have a material adverse impact on its financial condition or future results of operations.

Natural Gas Royalties Qui Tam Litigation

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

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

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

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

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

The relator has filed a claim in PG&E s Chapter 11 case for $2.5 billion, $2 billion of which is based upon the plaintiff s calculation of penalties sought against PG&E.

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

Order Instituting Investigation into Holding Company Activities

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

On January 9, 2002, the CPUC issued an interim decision and order interpreting the first priority condition adopted in the CPUC s holding company decision. This condition requires that the capital requirements of PG&E, as determined to be necessary and prudent to meet the utility s obligation to serve or to operate the utility in a prudent and efficient manner, be given first priority by the board of directors of the holding company. In the interim order, the CPUC stated, the first priority condition does not preclude the requirement that the holding company infuse all types of capital into their respective utility subsidiaries where necessary to fulfill PG&E s obligation to serve. The three major California IOUs and their parent holding companies had opposed the broader interpretation, first contained in a proposed decision released for comment on December 26, 2001, 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. The utilities applications for rehearing were denied on July 17, 2002.

In a related decision, the CPUC denied the motions filed by the California utility holding companies to dismiss the holding companies from the pending investigation on the basis that the CPUC lacks jurisdiction over the holding companies. However, in the interim decision interpreting the first priority condition discussed above, the CPUC separately dismissed PG&E Corporation (but no other utility holding company) as a respondent to the proceeding. In its written decision adopted on January 9, 2002, the CPUC stated that PG&E Corporation was being dismissed so that an appropriate legal forum could decide expeditiously whether adoption of PG&E s original proposed plan of reorganization would violate the first priority condition. The utilities applications for rehearing were denied on July 17, 2002.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

The holding companies petitions for review of these CPUC decisions are pending before the First Appellate District in San Francisco, California.

The proposed settlement agreement in PG&E s Chapter 11 proceeding provides that on or as soon as practicable after the later of the effective date of the Settlement Plan or the date the CPUC decision approving the proposed settlement agreement is final and nonappealable, PG&E, PG&E Corporation, on the one hand, and the CPUC, on the other, will execute full mutual releases and dismissals with prejudice of certain claims, actions or regulatory proceedings, as specified in the settlement agreement, arising out of or related in any way to the energy crisis or the implementation of AB 1890, including the CPUC s investigation into past holding company actions during the energy crisis (but only as to past actions, not prospective matters).

PG&E believes that PG&E and PG&E Corporation have complied with applicable statutes, CPUC decisions, rules, and orders. However, PG&E cannot predict what the outcome of the CPUC s investigation will be or whether the outcome will have a material adverse effect on its results of operations or financial condition.

Complaints Filed by the California Attorney General, City and County of San Francisco, and Cynthia Behr

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

Among other allegations, the California Attorney General alleged that, through PG&E s Chapter 11 proceedings, PG&E Corporation and PG&E engaged in unlawful, unfair, and fraudulent business practices in alleged violation of California Business and Professions Code Section 17200 (Section 17200) by seeking to implement the transactions contemplated in the original proposed plan of reorganization filed in PG&E s Chapter 11 proceeding. The complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from California PG&E. In February 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the California Attorney General s complaint to the Bankruptcy Court, as well as a motion to dismiss the lawsuit, or in the alternative, to stay the suit with the Bankruptcy Court. Subsequently, the California Attorney General filed a motion to remand the action to state court. In June 2002, the Bankruptcy Court held that federal law preempted the California Attorney General s allegations concerning PG&E Corporation s participation in PG&E s Chapter 11 proceedings. The Bankruptcy Court directed the California Attorney General to file an amended complaint omitting these allegations and remanded the amended complaint to the San Francisco Superior Court. Both parties appealed the Bankruptcy Court s remand order to the U.S. District Court for the Northern District of California (Northern District). The appeal and cross-appeal were argued before the Northern District on July 24, 2003, and the parties are waiting for a decision.

On August 9, 2002, the California Attorney General filed its amended complaint in the San Francisco Superior Court, omitting the allegations concerning PG&E Corporation s participation in PG&E s Chapter 11 proceedings. A status conference has been scheduled for August 29, 2003.

In addition, a second case, entitled *Cynthia Behr v. PG&E Corporation, et al.*, was filed on February 14, 2002, by a private plaintiff (who also has filed a claim under Chapter 11) in Santa Clara Superior Court also alleging a violation of Section 17200. The Behr complaint also names the directors of PG&E Corporation and PG&E as defendants. The allegations of the complaint are similar to the allegations contained in the California Attorney General s complaint but also include allegations of conspiracy, fraudulent transfer, and violation of the California bulk sales laws. The plaintiff requests the same remedies as the California Attorney General s case and in addition requests damages, attachment, and restraints upon the transfer of defendants property. In March 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the complaint to the

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

Bankruptcy Court. Subsequently, the plaintiff filed a motion to remand the action to state court. In its June 2002 ruling mentioned above as to the California Attorney General s and the City and County s cases, the Bankruptcy Court retained jurisdiction over Behr s fraudulent transfer claim and bulk sales claim, finding them to belong to PG&E s Chapter 11 estate. The Bankruptcy Court remanded Behr s Section 17200 claim to the Santa Clara Superior Court. Both parties have appealed the Bankruptcy Court s remand order to the Northern District. The appeal and cross-appeal were argued before the Northern District on July 24, 2003, and the parties are waiting for a decision.

In April 2003, the San Francisco Superior Court dismissed Behr s civil conspiracy cause of action. A status conference has been scheduled for August 29, 2003.

The California Attorney General s case has been coordinated by the San Francisco Superior Court with the cases filed by the City and County of San Francisco and Cynthia Behr.

PG&E believes that the allegations of the complaints are without merit and will vigorously respond to and defend against the litigation. PG&E cannot predict whether the outcome of the litigation will have a material adverse effect on its results of operations or financial condition.

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

On February 27, 2002, a group of 25 ratepayers filed a complaint against PG&E at the CPUC demanding an immediate reduction of approximately $0.035 per kWh in allegedly excessive electric rates and a refund of alleged recent over-collections in electric revenue since June 1, 2001. The complaint claims that electric rate surcharges adopted in the first quarter of 2001 due to the high cost of wholesale power (surcharges that increased the average electric rate by $0.04 per kWh) became excessive later in 2001. The only alleged over-collection amount calculated in the complaint is approximately $400 million during the last quarter of 2001. On April 2, 2002, PG&E filed an answer, arguing that the complaint should be denied and dismissed immediately as an impermissible collateral action and on the basis that the alleged facts, even if assumed to be true, do not establish that currently authorized electric rates are not reasonable. On May 10, 2002, PG&E filed a motion to dismiss the complaint. The CPUC has not yet issued a decision. However, in November 2002, the CPUC issued a decision jointly in this complaint case and in the rate stabilization proceedings modifying the restrictions on use of revenues generated by the surcharges to permit the revenues to be used for the purpose of securing or restoring PG&E s reasonable financial health, as determined by the CPUC. After the CPUC determines when the AB 1890 rate freeze ended, the CPUC will determine the extent and disposition of PG&E s under-collected costs, if any, remaining at the end of the rate freeze. If the CPUC determines that PG&E recovered revenues in excess of its transition costs or in excess of other permitted uses, the CPUC may require PG&E to refund such excess revenues. If the CPUC requires PG&E to refund any of these revenues in the future, PG&E s earnings could be materially affected. Under the proposed settlement agreement in PG&E s Chapter 11 proceeding, the CPUC would acknowledge and agree that the headroom, surcharge and base revenues accrued or collected by PG&E through and including December 31, 2003, are the property of PG&E s Chapter 11 estate, have been or will be used for utility purposes, including to pay creditors in PG&E s Chapter 11 proceeding, have been included in PG&E s retail electric rates consistent with state and federal law and are not subject to refund.

Note 5: Employee Benefit Plans

On May 28, 2003, two of PG&E s unions ratified new contracts, which provide for, among other items, an increase in benefits provided under its defined benefit pension plan (Retirement Plan). As a result of the ratifications, PG&E remeasured the assets and liabilities of the Retirement Plan at May 28, 2003. In connection with the remeasurement, which reflected a reduction in the current discount rate from the Retirement Plan s previous actuarial valuation, PG&E recorded a minimum pension obligation of $478 million, the amount by which the accumulated benefit obligation exceeded the fair market value of plan assets, and reduced its pension asset from $887 million to $353 million. PG&E has previously recognized a regulatory liability for timing differences between recognition of pension costs in accordance with GAAP and ratemaking purposes. As a result

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED JUNE 30, 2003 (Continued)

of the remeasurement, PG&E has reduced this regulatory liability by $911 million. The remaining amount of $60 million, net of income tax benefit of $41 million, has been recorded as a component of shareholders equity in OCI in the Consolidated Balance Sheets. The charge to OCI does not affect earnings or cash flow, and could be reversed in future periods if the fair value of plan assets exceeds the accumulated benefit obligation. PG&E s defined benefit pension plan currently exceeds the minimum funding requirements of the Employee Retirement Income Security Act of 1974.

Note 6: Subsequent Events

On July 2, 2003, PG&E Corporation completed a private placement of $600 million of 6 7/8 percent Senior Secured Notes due 2008 (Notes). The Notes are secured by a pledge of approximately 94 percent of the outstanding common stock of PG&E.

The indenture, dated as of July 2, 2003, does not contain restrictions on the ability of PG&E to incur debt.

$9,400,000,000

PACIFIC GAS AND ELECTRIC COMPANY

Debt Securities

PROSPECTUS

, 2003

PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 14. ***Other Expenses of Issuance and Distribution.***

The following table sets forth the costs and expenses, other than underwriting discounts and commissions, payable by us in connection with the sale of the debt securities being registered. All amounts, other than the registration fee, are estimates.

Registration fee	$760,460
Printing and engraving expenses	*
Legal fees and expenses	*
Accounting fees and expenses	*
Trustee s and authenticating agent s fees and expenses	*
Rating agencies fees	*
Blue sky fees and expenses	*
Miscellaneous	*
Total	$ *

* To be supplied by amendment.

Item 15. ***Indemnification of Directors and Officers.***

Section 317 of the California Corporations Code provides for indemnification of a corporation s directors and officers under certain circumstances. Our articles of incorporation authorize us to provide indemnification of any person who is or was a director, officer, employee or other agent of Pacific Gas and Electric Company, or is or was serving at the request of Pacific Gas and Electric Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise, or was a director, officer, employee or agent of a corporation which was a predecessor corporation of or of another enterprise at the request of the predecessor corporation through our bylaws, resolutions of our board of directors, agreements with agents, vote of shareholders or disinterested directors, or otherwise, in excess of the indemnification otherwise permitted by Section 317 of the California Corporations Code, subject only to the applicable limits set forth in Section 204 of the California Corporations Code. Our articles of incorporation also eliminate the liability of directors of Pacific Gas and Electric Company to the fullest extent permissible by California law. Our board of directors has adopted a resolution regarding our policy of indemnification and we maintain insurance which insures our directors and officers against certain liabilities.

Item 16. ***Exhibits.***

(a) Exhibits.

Number	Description
1	Form of Underwriting Agreement*
2.1	Order Confirming Plan of Reorganization*
2.2	Plan of Reorganization, dated July 31, 2003 (exhibits other than Exhibit D omitted)**
3	Amended and Restated Articles of Incorporation*
4.1	Form of Indenture between Pacific Gas and Electric Company and , as Trustee*

Number	Description
4.2	Form of Indenture between Pacific Gas and Electric Company and , as Trustee*
4.3	Form of Amended and Restated Indenture of Mortgage between Pacific Gas and Electric Company and , as Trustee*
5	Opinion of regarding the legality of the securities being registered*
12	Computation of ratios of earnings to fixed charges
23.1	Consent of Deloitte & Touche LLP
23.2	Consent of (included in Exhibit 5)*
24.1	Powers of Attorney
24.2	Resolutions of the Board of Directors of Pacific Gas and Electric Company
25.1	Form T-1 Statement of Eligibility under Trust Indenture Act of 1939 of , Trustee*
25.2	Form T-1 Statement of Eligibility under Trust Indenture Act of 1939 of , Trustee*

* To be filed by amendment.

** We undertake to provide a copy of each omitted exhibit supplementally to the SEC upon request.

Item 17. *Undertakings.*

The undersigned registrant hereby undertakes:

(1) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement:

(i) To include any prospectus required by Section 10(a)(3) of the Securities Act of 1933;

(ii) To reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement;

(iii) To include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement;

provided, however, that paragraphs (1)(i) and (1)(ii) do not apply if the information required to be included in a post-effective amendment by those paragraphs is contained in periodic reports filed with or furnished to the Commission by the Registrant pursuant to section 13 or section 15(d) of the Securities Exchange Act of 1934 that are incorporated by reference in this registration statement.

(2) That, for the purpose of determining any liability under the Securities Act of 1933, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof; and

(3) To remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering.

(4) That, for purposes of determining any liability under the Securities Act of 1933, each filing of the registrant s annual report pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 (and, where applicable, each filing of an employee benefit plan s annual report pursuant to Section 15(d) of the Securities Exchange Act of 1934) that is incorporated by reference in the registration statement shall be deemed

to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial *bona fide* offering thereof.

(5) Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the registrant pursuant to the provisions described under Item 15 above, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act of 1933 and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted against the registrant by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act of 1933 and will be governed by the final adjudication of such issue.

(6) For purposes of determining any liability under the Securities Act of 1933, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act of 1933 shall be deemed to be part of this registration statement as of the time it was declared effective. For the purpose of determining any liability under the Securities Act of 1933, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial *bona fide* offering thereof.

SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the registrant certifies that it has reasonable grounds to believe that it meets all of the requirements for filing on Form S-3 and has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the city of San Francisco, California, on October 24, 2003.

PACIFIC GAS AND ELECTRIC COMPANY
(Registrant)

By: * GORDON R. SMITH

Gordon R. Smith
President and Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
* GORDON R. SMITH Gordon R. Smith	President, Chief Executive Officer and Director (Principal Executive Officer)	October 24, 2003
* KENT M. HARVEY Kent M. Harvey	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	October 24, 2003
* DINYAR B. MISTRY Dinyar B. Mistry	Vice President and Controller (Principal Accounting Officer)	October 24, 2003
* DAVID R. ANDREWS David R. Andrews	Director	October 24, 2003
* DAVID A. COULTER David A. Coulter	Director	October 24, 2003
* C. LEE COX C. Lee Cox	Director	October 24, 2003
* WILLIAM S. DAVILA William S. Davila	Director	October 24, 2003
* ROBERT D. GLYNN, JR. Robert D. Glynn, Jr.	Director	October 24, 2003
* DAVID M. LAWRENCE	Director	October 24, 2003

David M. Lawrence

Signature	Title	Date
* MARY S. METZ Mary S. Metz	Director	October 24, 2003
* CARL E. REICHARDT Carl E. Reichardt	Director	October 24, 2003
* BARRY LAWSON WILLIAMS Barry Lawson Williams	Director	October 24, 2003

*By: /s/ GARY P. ENCINAS

Gary P. Encinas
attorney-in-fact

INDEPENDENT AUDITORS REPORT

To the Board of Directors and Shareholders of

Pacific Gas and Electric Company

We have audited the consolidated financial statements of Pacific Gas and Electric Company (a Debtor-in-Possession) and subsidiaries as of December 31, 2002 and 2001, and for each of the three years in the period ended December 31, 2002 and have issued our report thereon dated February 24, 2003, (which report expresses an unqualified opinion and includes explanatory paragraphs relating to (i) the adoption of new accounting standards in 2001 relating to derivative contracts, and (ii) the ability of Pacific Gas and Electric Company to continue as a going concern). Such consolidated financial statements are included herein. Our audits also included the consolidated financial statement schedule of Pacific Gas and Electric Company included herein. This consolidated financial statement schedule is the responsibility of the management of Pacific Gas and Electric Company. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements of Pacific Gas and Electric Company taken as a whole, presents fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP

San Francisco, California
February 24, 2003

SCHEDULE II

PACIFIC GAS AND ELECTRIC COMPANY

VALUATION AND QUANTIFYING ACCOUNTS

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
Valuation and qualifying accounts deducted from assets:					
2002:					
Allowance for uncollectible accounts(1)	$ 48	$ 35	$ (2)	$ 23(2)	$ 58
2001:					
Allowance for uncollectible accounts(1)	$ 52	$ 24	$	$ 28(2)	$ 48
Provision for loss on generation related regulatory assets and under collected purchased power costs(3)	$ 6,939	$	$	$ 6,939	$
2000:					
Allowance for uncollectible accounts(1)	$ 46	$ 19	$ 2	$ 15(2)	$ 52
Provision for loss on generation related regulatory assets and undercollected purchased power costs(3)	$	$ 6,939	$	$	$ 6,939

(1) Allowance for uncollectible accounts are deducted from Accounts Receivable Customers, net.

(2) Deductions consist principally of write-offs, net of collections of receivables previously written-off.

(3) Provision was deduction from Regulatory Assets.

EXHIBIT INDEX

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4.2	Form of Indenture between Pacific Gas and Electric Company and , as Trustee*
4.3	Form of Amended and Restated Indenture of Mortgage between Pacific Gas and Electric Company and , as Trustee*
5	Opinion of regarding the legality of the securities being registered*
12	Computation of ratios of earnings to fixed charges
23.1	Consent of Deloitte & Touche LLP
23.2	Consent of (included in Exhibit 5)*
24.1	Powers of Attorney
24.2	Resolutions of the Board of Directors of Pacific Gas and Electric Company
25.1	Form T-1 Statement of Eligibility under Trust Indenture Act of 1939 of , Trustee*
25.2	Form T-1 Statement of Eligibility under Trust Indenture Act of 1939 of , Trustee*

* To be filed by amendment.