PACIFIC GAS & ELECTRIC CO
Form S-3/A
March 02, 2004

As filed with the Securities and Exchange Commission on March 2, 2004

Registration No. 333-109994

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 1
to

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
Senior Secured Bonds	$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 senior secured bonds as may from time to time be issued at indeterminate prices; provided that in no event will the aggregate initial price of all senior secured bonds sold under this registration statement exceed $9,400,000,000. If any such senior secured bonds 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 senior secured bonds may exceed such amount.

(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(o) under the Securities Act, 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 senior secured bonds.

(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.

PROSPECTUS

$9,400,000,000

Pacific Gas and Electric Company

Senior Secured Bonds

Under this prospectus, we may offer and sell from time to time senior secured bonds, or senior bonds, 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 senior bonds that may be offered.

Each time we sell senior bonds, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered senior bonds. 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 senior bonds. This prospectus may not be used to sell senior bonds unless accompanied by a prospectus supplement.

After the effective date of our plan of reorganization, the senior bonds will be secured by a first lien, subject to permitted liens, on substantially all our real property and certain other tangible personal property related to our facilities. The lien securing the senior bonds, however, may be released in certain circumstances, subject to certain conditions. Upon a release of the lien, the senior bonds will cease to be our secured obligations and will become our unsecured general obligations, ranking *pari passu* with our other senior unsecured indebtedness.

The senior bonds 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 senior bonds, the aggregate principal amount of senior bonds 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 senior bonds 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.

March , 2004

TABLE OF CONTENTS

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

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 senior bonds with an aggregate initial offering price of up to $9.4 billion in one or more offerings.

This prospectus provides you with only a general description of the senior bonds 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 senior bonds, please refer to the registration statement of which this prospectus is a part. Each time we sell senior bonds, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered senior bonds. 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 senior bonds, 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 senior bonds 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:

the timing and resolution of the pending applications for rehearing of the approval by the California Public Utilities Commission, or the CPUC, of the settlement agreement it entered into with us on December 19, 2003, or the settlement agreement, and any appeals that may be filed with respect to the disposition of the rehearing applications;

the timing and resolution of the pending appeals of the confirmation by the U.S. Bankruptcy Court for the Northern District of California, or the bankruptcy court, of our plan of reorganization that incorporates the settlement agreement, or our plan of reorganization;

whether the investment grade credit ratings and other conditions required to implement our plan of reorganization are obtained or satisfied;

future equity and debt market conditions, future interest rates and other factors that may affect our ability to implement our plan of reorganization;

the impact of other current and future ratemaking actions of the CPUC, including the outcome of our 2003 general rate case;

prevailing governmental policies and legislative or regulatory actions generally, including those of the California legislature, the U.S. Congress, the CPUC, the Federal Energy Regulatory Commission, or the FERC, and the Nuclear Regulatory Commission, or the NRC, with regard to allowed rates of return, industry and rate structure, recovery of investments and costs, acquisitions and disposal of assets and facilities, treatment of affiliate contracts and relationships, and operation and construction of facilities, among other factors;

the extent to which the CPUC or the FERC delays or denies recovery of our costs, including electricity purchase costs, from customers due to a regulatory determination that the costs were not reasonable or prudent or for other reasons;

the extent to which our residual net open position increases or decreases (our residual net open position is the amount of electricity we need to meet the electricity demands of our customers, plus applicable reserve margins, that is not satisfied from our own generation facilities, our existing electricity purchase contracts and the California Department of Water Resources, or the DWR, electricity purchase contracts allocated to our customers, or the DWR allocated contracts);

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

unanticipated changes in our operating expenses or capital expenditures;

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

whether we are required to incur material costs or capital expenditures or curtail or cease operations at affected facilities to comply with existing and future environmental laws, regulations and policies;

increased competition as a result of the takeover by condemnation of our distribution assets, duplication of our distribution assets or service by local public utility districts, 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;

the extent to which our distribution customers switch between purchasing electricity from us and purchasing electricity from alternate energy service providers, thus becoming direct access customers, and the extent to which cities, counties and others in our service territory begin directly serving our customers or combine to form community choice aggregators;

the operation of our Diablo Canyon power plant, which exposes us to potentially significant environmental and capital expenditure outlays, 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;

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

the outcome of pending litigation;

whether we are determined to be in compliance with all applicable rules, tariffs and orders relating to electricity and natural gas utility operations, and the extent to which a finding of non-compliance could result in customer refunds, penalties or other non-recoverable expenses;

actions of credit rating agencies after the effective date of our plan of reorganization; and

significant changes in our relationship with our employees, the availability of qualified personnel and the potential adverse effects if labor disputes were to occur.

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 senior bonds. 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 senior bonds.

Risks Related to Us

If either or both of the CPUC s approval of the settlement agreement and the bankruptcy court s confirmation of our plan of reorganization are overturned or modified on rehearing or appeal, our financial condition and results of operations could be materially adversely affected.

The settlement agreement, which was approved by the CPUC in a decision issued on December 18, 2003, provides the basis for our plan of reorganization. On December 22, 2003, the bankruptcy court confirmed our plan of reorganization, which fully incorporates the settlement agreement as a material and integral part of the plan. On January 20, 2004, several parties filed applications with the CPUC requesting that the CPUC rehear and reconsider its decision approving the settlement agreement. Although the CPUC is not required to act on these applications within a specific time period, if the CPUC has not acted on an application within 60 days, that application may be deemed denied for purposes of seeking judicial review. In addition, the two CPUC commissioners who did not vote to approve the settlement agreement and a municipality have filed appeals of the bankruptcy court s confirmation order in the U.S. District Court for the Northern District of California, or the district court. If either or both of the CPUC s approval of the settlement agreement and the bankruptcy court s confirmation of our plan of reorganization are overturned or modified on rehearing or appeal, our financial condition and results of operations could be materially adversely affected.

In addition, the terms of our plan of reorganization permit us and Corp to cause our plan of reorganization to become effective and permit us to issue a significant portion of the senior bonds while the CPUC s approval of the settlement agreement and the bankruptcy court s confirmation of our plan of reorganization remain subject to appeal. If, after our plan of reorganization has become effective and the proceeds of any offering of the senior bonds have been released to us and used to pay allowed claims in our proceeding under Chapter 11 of the U.S. Bankruptcy Code, or our Chapter 11 proceeding, the bankruptcy court s confirmation order is subsequently overturned or modified, our ability to make payments on the senior bonds could be materially adversely affected.

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 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 U.S. Bankruptcy Code, or Chapter 11. Even though the settlement agreement and current regulatory mechanisms contemplate 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 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 allocated contracts, may not be sufficient to satisfy our customers electricity demands in the future. Our residual net open position is expected to grow 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;
- increases in our customers electricity demands due to customer and economic growth or other factors; and
- retirement or closure of our electricity generation facilities.

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 January 2004, the CPUC adopted an interim decision that would require the California investor-owned electric utilities to achieve, no later than January 1, 2008, an electricity reserve margin of 15-17% in excess of peak capacity electricity requirements and have a diverse portfolio of electricity sources. These requirements may increase our residual net open position. Specific procedures contained in the decision relating to development and execution of our procurement plans also may cause our cost of electricity to increase. The CPUC also continued its target of a 5% limitation on the reliance by the California investor-owned electric utilities on the spot market to meet their energy needs.

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 will find reasonable, or at all. Our financial condition and results of operations would be materially adversely affected if we are unable to purchase electricity in the wholesale market at prices or 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 natural gas 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 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 hazards 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 lower revenues or increased expenses, or both, that may not be fully recovered through insurance, rates or other means in a timely manner, or at all.

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;
- electricity transmission or natural gas transportation capacity constraints;
- federal, state and local energy and environmental regulation and legislation; and
- natural disasters, war, terrorism and other catastrophic events.

These factors are largely outside our control. If wholesale electricity or natural gas prices increase significantly, public pressure or other regulatory or governmental influences or other factors could constrain the willingness or ability of the CPUC to authorize timely recovery of 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 environmental compliance, monitoring and pollution control equipment, as well as for related fees and permits. Moreover, compliance in the future may require significant expenditures relating to electric and magnetic fields, or EMFs. We also are subject to significant liabilities related to the investigation and remediation of environmental contamination at our current and former facilities, as well as at third-party owned sites. Due to the potential for imposition of stricter standards and greater regulation in the future and the possibility that other potentially responsible parties may not be financially able to contribute to cleanup costs, conditions may change or additional contamination may be discovered, 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 purchasing 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, which permits 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. Once registration has occurred, each community choice aggregator would purchase electricity for all of its residents who do not affirmatively elect to continue to receive electricity from us. However, we would remain those customers electricity provider of last resort.

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 customers to migrate to 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 electing 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 changes in the number 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 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 power plant by the spring of 2007 and there are no other available spent fuel storage or disposal alternatives, we would be forced to close this plant and would therefore be required to purchase electricity from more expensive sources.

Under the terms of the NRC operating licenses for 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. In addition, discharge permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. 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 Senior Bonds

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 senior bonds.

After giving effect to our plan of reorganization (including the issuance of a significant portion of the senior bonds in connection with our plan of reorganization, reinstatement of certain pollution control bond-related obligations and payments to holders of allowed claims), we currently expect to have up to approximately $9.4 billion in total debt outstanding immediately after the effective date of our plan of reorganization (excluding rate reduction bonds and draws on our contemplated revolving credit and accounts receivable facilities). In addition, the indenture governing the senior bonds and the terms of our contemplated credit facilities will allow us to incur additional debt. Our level of debt could have important consequences to holders of the senior bonds. 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, regulatory and industry conditions.

Our ability to make scheduled payments of principal and interest on the senior bonds and to satisfy our 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 amount of debt we expect to have outstanding after giving effect to our plan of reorganization and the establishment of the contemplated credit and accounts receivable facilities, as well as future indebtedness levels, could adversely affect our ability to make payments of principal and interest on the senior bonds.

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

There is no existing market for the senior bonds and we do not intend to apply for listing of the senior bonds 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 senior bonds, the ability of the holders of the senior bonds to sell their senior bonds or the price at which holders of the senior bonds will be able to sell their senior bonds. Future trading prices of the senior bonds will depend on many factors, including prevailing interest rates, our financial condition and results of operations, the then-current ratings assigned to the senior bonds and the market for similar securities.

If a particular offering of senior bonds is sold to or through underwriters, the underwriters may attempt to make a market in the senior bonds. 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 senior bonds does not develop, holders of those senior bonds may be unable to resell them for an extended period of time and those senior bonds 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 senior bonds.

The indenture for the senior bonds restricts the amount and type of secured indebtedness that we may incur. Our contemplated credit facilities also 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 senior bonds. 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 senior bonds.

The senior bonds are expected to become unsecured obligations in the future.

When the senior bonds are issued, they will be secured by a lien on substantially all of our real property and certain tangible personal property related to our facilities. The indenture provides that the lien may be released when the ratings assigned by Moody s Investors Service, or Moody s, and Standard & Poor s, or S&P, on our long-term unsecured debt obligations immediately after the release of the lien would be at least equal to the initial ratings on the senior bonds issued to the public in connection with our plan of reorganization and when the aggregate amount of debt secured by a lien on any principal property that would be outstanding after the date the lien is released, or the release date, excluding debt secured by specified liens, would not exceed 5% of our tangible net assets, as defined in the indenture. After the release date, there will be no collateral securing the senior bonds and the senior bonds will become our unsecured general obligations ranking *pari passu* with all of our other senior unsecured debt. In addition, if our senior unsecured credit ratings fall after the release date, we will not be required to again secure the senior bonds. We also may maintain and incur certain types and amounts of secured debt after the release date. The absence of collateral securing the senior bonds could materially adversely affect the ability of holders of the senior bonds to collect payments should we default on our obligations or go back into bankruptcy after the effective date of our plan of reorganization.

Holders of senior bonds may be limited in their remedies with respect to the collateral.

If an event of default occurs under the indenture for the senior bonds before the release date, the trustee under the indenture has the right to exercise remedies against the collateral securing the senior bonds. The trustee will take any action, if requested to do so by the holders of at least 33% (at least a majority prior to the release date) of the aggregate principal amount of outstanding senior bonds and if the trustee has been offered reasonable indemnity. Thus, you may not be able to control the trustee s exercise of remedies unless you can obtain the consent of at least 33% (at least a majority prior to the release date) of the aggregate principal amount of outstanding senior bonds and provide the trustee with reasonable indemnity. In addition, provisions of California law limit the remedies of a lender secured by a mortgage. In light of the extensive number of real properties subject to the lien of the indenture, foreclosure may be very difficult and time consuming. In addition, the sale or other disposition of all or a portion of our real property in connection with a foreclosure could require approval or other action by applicable regulatory authorities, including the CPUC, the FERC and the NRC. If we go back into bankruptcy after the effective date of our plan of reorganization, there could be adverse effects on the senior bonds that could result in delays or reductions in payments to the holders of the senior bonds. In addition, bankruptcy could have an adverse effect on the liquidity and value of the senior bonds.

The sale of the collateral may provide insufficient proceeds to satisfy all the obligations secured by the collateral.

The senior bonds will be secured by a lien on substantially all of our real property and certain tangible personal property related to our facilities. The value of the property in the event of liquidation will depend upon market and economic conditions, the availability of buyers and other factors. Some or all of the real and personal property subject to the lien of the indenture may be illiquid, may have no readily ascertainable market value or may not be saleable on a timely basis or at all. If the proceeds of the sale of the property subject to the lien are not sufficient to repay all amounts due on the senior bonds, your right to obtain the shortfall from us or from our remaining assets may be limited or eliminated by California law. Since the indenture will permit us to secure other obligations with liens on any of our properties or assets that do not secure the senior bonds, our remaining assets available to satisfy our obligations to you may be further reduced. In addition, the indenture permits us to issue additional secured debt, including additional senior bonds. This could reduce amounts payable to you from the proceeds of the sale of collateral.

USE OF PROCEEDS

Each prospectus supplement will describe the uses of the proceeds from the issuance of the senior bonds offered by that prospectus supplement.

SELECTED CONSOLIDATED FINANCIAL DATA

The following table presents our selected consolidated financial data for the years ended December 31, 2003, 2002, 2001, 2000 and 1999. We derived the selected consolidated financial data for the years ended December 31, 2003, 2002 and 2001 from our audited consolidated financial statements included in this prospectus and the selected consolidated financial data for the years ended December 31, 2000 and 1999 from our consolidated financial statements not included in this prospectus. 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.

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(dollars in millions)				
Consolidated Statements of Operations Data:					
Operating revenues:					
Electricity	$ 7,582	$ 8,178	$ 7,326	$ 6,854	$7,232
Natural gas	2,856	2,336	3,136	2,783	1,996
Total operating revenues	10,438	10,514	10,462	9,637	9,228
Operating expenses:					
Depreciation, amortization and decommissioning	1,218	1,193	896	3,511	1,564
Other operating expenses	6,881	5,408	7,088	11,327	5,671
Total operating expenses	8,099	6,601	7,984	14,838	7,235
Operating income (loss)(1)	2,339	3,913	2,478	(5,201)	1,993
Interest expense(2)	(953)	(988)	(974)	(619)	(593)
Other income	66	72	107	183	36
Income tax (provision) benefit	(528)	(1,178)	(596)	2,154	(648)
Net income (loss) from continuing operations(1)	924	$ 1,819	$ 1,015	$ (3,483)	$ 788
Other Data (unaudited):					
Ratio of earnings to fixed charges(3)	2.51x	3.91x	2.58x	x(4)	3.25x
EBITDA(5)	$ 3,623	$ 5,178	$ 3,481	$ (1,507)	$3,593

	December 31,				
	2003	2002	2001	2000	1999
	(in millions)				
Consolidated Balance Sheet Data:					
Cash and cash equivalents	$ 2,979	$ 3,343	$ 4,341	$ 1,344	$ 101
Restricted cash	403	150	53	50	
Working capital	3,555	3,399	4,291	(6,192)	(1,603)
Net property, plant and equipment	18,102	16,978	16,193	15,635	15,110
Total assets	29,066	27,593	28,105	24,622	23,862
Debt, classified as current	600	571	623	5,743	1,204
Long-term debt	2,431	2,739	3,019	3,342	4,877
Rate reduction bonds (excluding current portion)	870	1,160	1,450	1,740	2,031
Liabilities subject to compromise	9,502	9,408	11,384		
Preferred securities with mandatory redemption provisions	137	137	437	437	437
Shareholders equity	5,089	4,194	2,398	1,410	5,771

(1) Operating income (loss) and net income (loss) from continuing operations reflect the write-off of generation-related regulatory assets and undercollected electricity purchase costs in 2000.

(2) Interest expense includes non-contractual interest expense of $131 million, $149 million and $164 million for the years ended December 31, 2003, 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 a comparative measure 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). The following is a reconciliation of EBITDA to both net income (loss) from continuing operations and net cash provided by operating activities:

	Year Ended December 31,				
	2003	**2002**	**2001**	**2000**	**1999**
			(in millions)		
Net income (loss) from continuing operations	$ 924	$ 1,819	$1,015	$(3,483)	$ 788
Adjustments to reconcile EBITDA to net income (loss) from continuing operations:					
Depreciation, amortization and decommissioning	1,218	1,193	896	3,511	1,564
Interest expense	953	988	974	619	593
Income tax provision (benefit)	528	1,178	596	(2,154)	648
EBITDA	$3,623	$ 5,178	$3,481	$(1,507)	$ 3,593
Adjustments to reconcile EBITDA to net cash provided by operating activities:					
Cash paid for interest	(773)	(1,105)	(361)	(587)	(531)
Cash (paid) refunded for taxes	(648)	(1,186)	556		(1,001)
Deferral of electric procurement costs				(6,465)	
Provision for loss on generation-related regulatory assets and undercollected purchased power costs				6,939	
Reversal of Independent System Operator accrual		(970)			
Change in deferred charges and other non-current liabilities	581	102	(954)	480	101
Change in working capital (other than income taxes payable)	(653)	363	2,379	2,263	464
Payments authorized by bankruptcy court	(87)	(1,442)	(16)		
Other, net	(73)	194	(320)	(568)	(430)
Net cash provided by operating activities	$1,970	$ 1,134	$4,765	$ 555	$ 2,196

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 public utility operating in northern and central California. We engage primarily in the businesses of electricity and natural gas distribution, electricity generation, electricity transmission, and natural gas transportation and storage. We are a wholly owned subsidiary of Corp. We were incorporated in California in 1905.

We served approximately 4.9 million electricity distribution customers and approximately 3.9 million natural gas distribution customers at December 31, 2003. We had approximately $29.1 billion in assets at December 31, 2003 and generated revenues of approximately $10.4 billion in 2003. Our revenues are generated mainly through the sale and delivery of electricity and natural gas. We are regulated primarily by the CPUC and the FERC.

Restructuring of the California Electricity Industry

In 1996, California enacted Assembly Bill, or 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 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 greater than these costs, to recover our costs stranded by the regulatory change, or transition costs.

AB 1890 also gave customers the choice of continuing to buy electricity from the California investor-owned electric utilities or, beginning in April 1998, becoming direct access customers. We bill direct access customers based on fully bundled rates, or rates that include electricity procurement, generation, distribution, transmission and other components. We then give direct access customers energy credits equal to the procurement component of the fully bundled rates, or direct access credits.

The California Energy Crisis and Our Chapter 11 Proceeding

Beginning in May 2000, wholesale electricity prices began to increase so that the frozen rates were not sufficient to recover our operating and electricity procurement costs. We financed the higher costs of wholesale electricity by issuing debt in the fall of 2000 and drawing on our credit facilities. Ultimately, our inability to recover our electricity procurement costs from our customers resulted in billions of dollars in defaulted debt and unpaid bills. On April 6, 2001, we filed a voluntary petition for relief under the provisions of Chapter 11 in the bankruptcy court. We retained control of our assets and are authorized to operate our business as a debtor-in-possession during our Chapter 11 proceeding.

In January 2001, because of the deteriorating credit of the California investor-owned electric utilities, the DWR began purchasing electricity to meet each utility s net open position, which is the portion of the demand of a utility s customers, plus applicable reserve margins, not satisfied from that utility s own generation facilities and existing electricity contracts. The DWR is currently legally and financially responsible for its electricity contracts. The DWR pays for its costs of purchasing electricity from a revenue requirement collected from electricity customers of the three California investor-owned electric utilities through what is known as a power charge. These customers also must pay another revenue requirement, which is known as a bond charge, for the DWR s costs associated with its $11.3 billion bond offering completed in November 2002. On January 1, 2003, each California investor-owned electric utility resumed purchasing electricity to meet its residual net open position.

In January 2001, the CPUC authorized us to collect the first of three electricity surcharges intended to help us reduce the impact of the high wholesale electricity prices. The rate surcharges totaled $0.045 per kWh, and were fully implemented by June 2001.

In mid-2001, wholesale electricity prices moderated. As a result of these surcharges and moderating electricity prices, our net income and cash balances increased. This has allowed us to pay our post-petition operating expenses and other post-petition liabilities with internally generated funds. In addition, we have paid interest on certain pre-petition liabilities and the principal of maturing mortgage bonds with bankruptcy court approval.

Our Plan of Reorganization and Settlement Agreement

In September 2001, we and Corp proposed a plan of reorganization that would have disaggregated our businesses. In April 2002, the CPUC, later joined by the Official Committee of Unsecured Creditors, proposed an alternate plan of reorganization that would not have disaggregated our businesses. On December 19, 2003, we, the CPUC and Corp entered into the settlement agreement that contemplated a new plan of reorganization to supersede the competing plans. Under the settlement agreement, we remain vertically integrated. On December 22, 2003, the bankruptcy court confirmed our plan of reorganization, which fully incorporates the settlement agreement. Our plan of reorganization provides that we will pay all allowed creditor claims in full (except for the claims of holders of certain pollution control bond-related obligations that will be reinstated) from the proceeds of the public offering of a significant portion of the senior bonds, cash on hand and draws on credit and accounts receivable facilities. At December 31, 2003, allowed claims in our Chapter 11 proceeding amounted to approximately $12.3 billion.

The settlement agreement permits us to emerge from Chapter 11 as an investment grade entity by generally ensuring that we will have the opportunity to collect in rates reasonable costs of providing our utility service. The settlement agreement provides that our authorized return on equity will be no less than 11.22% per year and, except for 2004 and 2005, our authorized equity to capitalization ratio, or authorized equity ratio, will be no less than 52% until Moody s has issued us an issuer rating of not less than A3 or S&P has issued us a long-term issuer credit rating of not less than A-. The settlement agreement establishes a $2.21 billion after-tax regulatory asset and allows for the recognition of an approximately $800 million after-tax regulatory asset related to generation assets. The settlement agreement and related decisions by the CPUC provide that our revenue requirement will be collected regardless of sales levels and that our rates will be timely adjusted to accommodate changes in costs that we incur.

On January 20, 2004, several parties filed applications with the CPUC requesting that the CPUC rehear and reconsider its decision approving the settlement agreement. Although the CPUC is not required to act on these applications within a specific time period, if the CPUC has not acted on an application within 60 days, that application may be deemed denied for purposes of seeking judicial review. In addition, the two CPUC commissioners who did not vote to approve the settlement agreement and a municipality have appealed the bankruptcy court s confirmation order in the U.S. District Court for the Northern District of California, or the district court. On January 5, 2004, the bankruptcy court denied a request to stay the implementation of our plan of reorganization until the appeals are resolved. The district court will set a schedule for briefing and argument of the appeals at a later date. No additional parties may request rehearings or make appeals of the CPUC s approval of the settlement agreement or the bankruptcy court s confirmation order.

Implementation of our plan of reorganization is subject to various conditions, including the consummation of the public offering of the senior bonds, the receipt of investment grade credit ratings and final CPUC approval of the settlement agreement. 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 by us and Corp to constitute final approval. Thus, the terms of our plan of reorganization permit us and Corp to cause our plan of reorganization to become effective (and permit us to issue a significant portion of the senior bonds) while the CPUC s approvals are subject to pending appeals or further rights of appeal. Until certain conditions or events regarding the effectiveness of our plan of reorganization discussed above are resolved further, we do not believe that the applicable accounting probability standard needed to record the regulatory assets contemplated by the settlement agreement has been met. We believe that we and the senior bonds to be issued in connection with our plan of reorganization will receive investment grade credit ratings. We expect that the sale of the senior bonds will be the last condition of our plan of reorganization to be satisfied. Our plan of reorganization provides that the effective date will occur 11 business days after all the conditions have been satisfied or, with respect to certain conditions, waived by us and Corp. There can be no assurance that the settlement agreement will not be modified on rehearing or appeal or that our plan of reorganization will become effective.

2004 Rate Reduction

In early January 2004, the CPUC issued a decision finding that the rate freeze mandated by AB 1890 ended on January 18, 2001. In mid-January 2004, we entered into a rate design settlement agreement, or rate design settlement, with representatives of major customer groups that addresses revenue allocation and rate design issues associated with the decrease in our revenue requirements resulting from the settlement agreement, DWR revenue requirements and other CPUC actions. On February 26, 2004, the CPUC issued a decision adopting the rate design settlement. This decision, combined with the January 2004 CPUC decision regarding the rate freeze, provides that we will no longer collect the frozen rates and surcharges. Instead, we will collect the regulatory assets arising from the settlement agreement, as amortized into rates, the revenue requirements established by the 2003 general rate case and revenue requirements established in other proceedings. We have reached an agreement, or general rate case settlement, with several consumer groups to resolve our 2003 general rate case and set our electricity and natural gas revenue requirements and our electricity generation revenue requirement through 2006. The general rate case settlement is pending CPUC approval. As a result of the approval of the rate design settlement, our electricity customers will receive an electricity rate reduction of approximately 8.0% on average, starting in March 2004, or shortly thereafter, retroactive to January 1, 2004. We expect that as a result of this rate reduction, our electricity operating revenues will decrease by approximately $799 million compared to revenues generated at rates in effect prior to the implementation of the rate design settlement. If the general rate case settlement is not approved, the net average reduction in electricity rates and associated reduction in electricity operating revenue will be even greater.

Significant Factors Affecting Results

Our results of operations will be affected by whether and when the settlement agreement and our plan of reorganization are implemented. Other significant factors that affect our results of operations include:

- CPUC decisions affecting the rates that we can charge for our services and determining the costs that are allowable for recovery within our rate structure;
- the amount and cost of electricity purchased;
- other operating expenses; and
- the performance of distribution, generation, transmission and transportation operating assets.

The CPUC has broad influence over our operations. Our revenue requirements are authorized primarily by the CPUC and the CPUC approves the rates that we charge our customers. The CPUC is responsible for setting service levels and certain operating practices which have a significant impact on the amount of costs we incur. The CPUC is also responsible for reviewing our capital and operating costs and in certain cases prescribes specific accounting treatment.

Electricity procurement costs historically have impacted our results of operations and financial condition. California legislation has been enacted which allows us to recover substantially all our prospective wholesale electricity procurement costs and requires the CPUC to adjust rates on a timely basis to ensure that we recover our costs. Accordingly, for 2004 and beyond, electricity procurement costs are not expected to have the same impact on our results of operations that they had during the California energy crisis. However, the level of our electricity procurement costs will continue to have an impact on our cash flows.

Operating expenses are a key factor in determining whether we earn the rate of return authorized by the CPUC. Many of our costs, including electricity procurement costs, discussed above, are subject to ratemaking mechanisms that are intended to provide us the opportunity to fully recover these costs. However, there is no ratemaking mechanism for recovery of our operating and maintenance expenses. As a result, changes in our operating expenses impact our results of operations.

Our distribution, generation, transmission and transportation operating assets generally consist of long-lived assets with significant construction and maintenance costs. Our annual capital expenditures are expected to average approximately $1.7 billion annually over the next five years. A significant outage at any of our facilities may have a material impact on our operations. Costs associated with replacement electricity and natural gas or use of alternative facilities during these outages could have an adverse impact on our results of operations and liquidity.

Reporting

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.

The consolidated financial statements include our accounts and those of our wholly owned and controlled subsidiaries. This Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the consolidated financial statements and notes to the consolidated financial statements.

Our Chapter 11 Proceeding and CPUC Settlement Agreement

On December 19, 2003, we, Corp and the CPUC entered into the settlement agreement and, on December 22, 2003, the bankruptcy court confirmed our plan of reorganization which fully incorporates the settlement agreement.

Terms and Financial Impact of the Settlement Agreement

The principal terms of the settlement agreement that will affect our results of operations and liquidity include:

Regulatory Assets. The settlement agreement establishes 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 to be amortized on a mortgage-style basis over nine years retroactive to January 1, 2004. Under this amortization methodology, annual after-tax collections of the $2.21 billion regulatory asset in electricity rates are estimated to range from approximately $140 million in 2004 to approximately $380 million in 2012, although these amounts will be reduced as discussed below. The unamortized balance of this after-tax regulatory asset will earn a rate of return on its equity component of no less than 11.22% annually for its nine-year term. The rate of return on this regulatory asset would be eliminated if we complete the refinancing discussed below. Instead, we would collect from customers amounts sufficient to service the securitized debt. The net after-tax amount of any refunds, claim offsets or other credits we receive from energy suppliers related to specified electricity procurement costs incurred during the California energy crisis, including from a settlement, or the El Paso settlement, involving El Paso Natural Gas Company, or El Paso, related to electricity refunds, but not natural gas refunds, will reduce the outstanding balance of this regulatory asset. Under the rate design settlement approved by the CPUC on February 26, 2004, the reduction to the regulatory asset related to the El Paso settlement and certain other generator refunds, claim offsets or other credits is forecast to be $179 million, after-tax. The estimated amount will be subject to adjustment based on actual amounts received by us. Additional refunds, claim offsets and other credits would further reduce this regulatory asset. Reductions of the regulatory asset reduce the amount amortized into rates.

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

We expect to recognize the pre-tax amounts of the two regulatory assets once we determine, in accordance with GAAP, that these regulatory assets are probable of recovery, as discussed above. This recognition would increase our total assets by approximately $5.0 billion. It also will result in the recording of approximately $2.0 billion of deferred tax liabilities that would be recognized as income tax expense. In addition, the recognition of these regulatory assets and related deferred taxes will result in a one-time non-cash gain of approximately $3.0 billion of net income for the year of recognition, with a similar increase in our shareholders equity. The portion of these amounts attributable to the $2.21 billion after-tax regulatory asset will be reduced for refunds, claim offsets and other credits received.

Ratemaking. Under the terms of the settlement agreement, the CPUC has agreed to act timely upon our applications to collect in rates prudently incurred costs of any new, reasonable investment in utility plant and assets and has agreed to timely adjust our rates to ensure that we collect in rates fixed amounts to service existing rate reduction bonds, regulatory asset amortization and return and base revenue requirements. In addition, the CPUC has agreed to set our capital structure and authorized return on equity in our annual cost of capital proceedings in its usual manner. From January 1, 2004 until Moody s has issued an issuer rating for us of not less than A3 or S&P 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 will be no less than 52%. However, for 2004 and 2005, our authorized equity ratio will equal the greater of the proportion of equity approved in our 2004 and 2005 cost of capital proceedings, or 48.6%.

The CPUC agreed in the settlement agreement to maintain our retail electricity rates at their pre-existing level through the end of 2003. In 2004, we will no longer collect the revenue generated by the frozen rates and surcharges that we collected in 2003, 2002 and 2001. Instead, we will collect revenues designed to recover the regulatory assets, as amortized into rates, and the revenue requirements established by the 2003 general rate case and other regulatory proceedings. Although revenue requirements would increase over previously authorized amounts if the pending general rate case settlement is approved by the CPUC, the elimination of the surcharges and frozen rates will result in a net average reduction of electricity rates effective March 2004, or shortly thereafter, retroactive to January 1, 2004. In addition, we will recognize expenses related to the amortization of the regulatory assets in 2004 and beyond, expenses not present in 2003. The amortization of the regulatory assets would have no direct impact on cash flow because amortization is a non-cash expense. The decrease in rates will, however, reduce cash flow. Other than the one-time impact of recording net income associated with recognition of the regulatory assets discussed above, overall implementation of the settlement agreement and related rulemaking will decrease our net income in 2004 as compared to 2003. In addition, if the general rate case settlement is not approved, the amount of the rate reduction and revenue reduction will increase.

Securitization. We and Corp have agreed to seek to refinance up to a total of $3.0 billion of the unamortized pre-tax balance of the $2.21 billion after-tax regulatory asset, as expeditiously as practicable after the effective date of our plan of reorganization using a financing supported by a dedicated rate component, provided certain conditions are met. These conditions include the enactment of authorizing California legislation satisfactory to us, the CPUC, and The Utility Reform Network, or TURN, and that the securitization not adversely affect our credit ratings. We expect to use the securitization proceeds to rebalance our capital structure in order to achieve the capital structure provided in the settlement agreement.

After the securitization, the rate of return on this regulatory asset would be eliminated. Instead, we would collect from customers amounts sufficient to service the securitized debt. Electricity rates would be further reduced to reflect the lower cost of capital of the securitization financing, causing a corresponding decrease in our net income.

Cash Requirements of Our Plan of Reorganization

Our plan of reorganization provides for payment in full in cash of all allowed creditor claims (except for the claims of holders of approximately $814 million 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 outstanding preferred stock. The following is a summary of all claims we have recorded at December 31, 2003 (including all claims related to obligations that will be reinstated at the effective date of our plan of reorganization):

	Amount Owed
	(in millions)
Revolving line of credit	$ 938
Bank borrowing letters of credit for accelerated pollution control loan agreements	454
Floating rate notes	1,240
Commercial paper	873
Senior notes	680
Pollution control loan agreements	814
Medium-term notes	287
Deferrable interest subordinated debentures	300
Other long-term debt	17
Financing debt subject to compromise	5,603
Trade creditors subject to compromise	3,899
Mortgage bonds	2,741
Interest and dividends	20
Total	$ 12,263

On March 1, 2004, we made an approximately $310 million principal payment on maturing mortgage bonds with bankruptcy court approval. We expect to pay all remaining allowed claims (other than claims represented by reinstated obligations) on or as soon as practicable after the effective date of our plan of reorganization and to establish escrow accounts to pay disputed claims as they are resolved. We expect that we will require approximately $11.0 billion in cash to pay the allowed claims and make the necessary escrow deposits. In addition, $814 million outstanding under the pollution control loan agreements will be reinstated. We expect to offset allowed power procurement claims with amounts owed to us by the California Power Exchange, or PX. This netting reduces the cash requirement of our plan of reorganization by approximately $500 million.

We expect to use approximately $2.8 billion of cash on hand after retirement of the mortgage bonds to pay allowed claims and make necessary escrow deposits. In accordance with our plan of reorganization, the balance of the cash requirements will be met with a public offering of a significant portion of the senior bonds and draws on various credit and accounts receivables facilities.

Results of Operations

The table below details certain items from the accompanying consolidated statements of operations for 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
Operating revenues			
Electricity	$ 7,582	$ 8,178	$ 7,326
Natural gas	2,856	2,336	3,136
Total operating revenues	10,438	10,514	10,462
Operating expenses			
Cost of electric energy	2,319	1,482	2,774
Cost of natural gas	1,467	954	1,832
Operating and maintenance	2,935	2,817	2,385
Depreciation, amortization and decommissioning	1,218	1,193	896
Reorganization professional fees and expenses	160	155	97
Total operating expenses	8,099	6,601	7,984
Operating income	2,339	3,913	2,478
Reorganization interest income	46	71	91
Interest income	7	3	32
Interest expense:			
Contractual interest expense	(822)	(839)	(810)
Noncontractual interest expense	(131)	(149)	(164)
Other income (expense), net	13	(2)	(16)
Income before income taxes	1,452	2,997	1,611
Income tax provision	528	1,178	596
Income before cumulative effect of a change in accounting principle	924	1,819	1,015
Cumulative effect of a change in accounting principle (net of income tax benefit of $1 million for 2003)	(1)		
Net income	923	1,819	1,015
Preferred dividend requirement	22	25	25
Income available for (allocated to) common stock	$ 901	$ 1,794	$ 990

Overview

The following presents our operating results for 2003, 2002 and 2001. As described below, net income for 2003 reflects a decline in operating revenues compared to 2002 as a result of increases in the DWR s revenue requirements and an increased cost of electricity because we resumed procuring electricity to cover our residual net open position in 2003. Net income for 2002 reflects an increase in operating revenues compared to 2001 due to increased electricity surcharge collections and a decrease in amounts passed through to the DWR. Although we are not able to predict all of the factors that may affect future results, results of operations in 2004 will be materially different from historical results if the settlement agreement is implemented, if the CPUC approves our general rate case settlement and as the rate design settlement is implemented.

Electricity Operating Revenues

From mid-January 2001 through December 2002, the DWR was responsible for procuring electricity required to cover our net open position. We resumed purchasing electricity on the open market in January 2003 to satisfy our residual net open position, but still rely on electricity provided under DWR contracts for a material portion of our customers demand. Revenues collected on behalf of the DWR and the DWR s related costs are not included in our consolidated statements of operations, reflecting our role as a billing and collection agent for the DWR s sales to our customers. Under the frozen rate structure, increases in the revenues passed through to the DWR decreased our revenues.

In January 2001, the CPUC authorized us to collect an electricity surcharge, the first of three surcharges intended to help the California investor-owned electric utilities pay for the high cost of wholesale electricity. The surcharges, totaling $0.045 per kWh, were fully implemented by June 2001 and were collected through December 31, 2003, while frozen rates remained in place.

The following table shows a breakdown of our electricity operating revenue by customer class:

	2003	2002	2001
		(in millions)	
Residential	$ 3,671	$ 3,646	$ 3,396
Commercial	4,440	4,588	4,105
Industrial	1,410	1,449	1,554
Agricultural	522	520	525
Miscellaneous	59	316	380
Direct access credits	(277)	(285)	(461)
DWR pass-through revenue	(2,243)	(2,056)	(2,173)
Total electricity operating revenues	$ 7,582	$ 8,178	$ 7,326

In 2003, our electricity operating revenues decreased approximately $596 million, or 7%, compared to 2002 mainly due to the following factors:

Pass-through revenue to the DWR increased by approximately $187 million, or 9%, in 2003 from 2002. This increase was mainly due to an aggregate increase of $1.0 billion in DWR power and bond charges, partially offset by an approximately $444 million reduction in the 2003 DWR revenue requirement and an approximately $369 million adjustment recorded in the third quarter of 2002 to reflect required changes to the methodology used to calculate DWR pass-through revenues.

The reduction in the DWR s 2003 revenue requirement was mainly due to a September 2003 CPUC decision that reduced the DWR s approved revenue requirement for 2003. The decision also required us to pass the benefit of the revenue requirement reduction on to our customers through a one-time bill credit in 2003. As a result, the approximately $444 million reduction in the 2003 DWR revenue requirement was offset by a corresponding reduction in electricity operating revenues for each customer class in 2003.

We recorded a regulatory liability or reserve for the potential refund of approximately $125 million of surcharge revenues collected in 2003 as provided by the terms of the rate design settlement entered into in January 2004 and approved by the CPUC on February 26, 2004.

Due to an April 2002 CPUC decision that increased baseline quantity allowances that was applied for all of 2003 but only a portion of 2002, electricity operating revenues decreased by an additional $44 million in 2003. 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 certain surcharges.

The decrease in electricity operating revenues was partially offset by the collection of a cost responsibility surcharge, a non-bypassable charge to direct access customers for their share of certain costs incurred by us. The CPUC implemented this surcharge on January 1, 2003 and we collected approximately $187 million in cost responsibility surcharge revenues from direct access customers in 2003.

In 2002, our electricity operating revenues increased approximately $852 million, or 12%, compared to 2001 mainly due to the following factors:

The amount of CPUC authorized surcharges increased approximately $751 million, or 34%, in 2002 from 2001. This increase reflects the collection of $0.045 per kWh in surcharges for all of 2002 compared to the collection of $0.01 per kWh in surcharges for substantially all of 2001 and the remaining $0.035 per kWh in surcharges for only seven months during 2001.

Direct access credits decreased approximately $176 million, or 38%, in 2002 from 2001 mainly due to a decrease in the average direct access credit per kWh, 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 lower in 2002 than in 2001 because in the beginning of 2001 we used the PX price for wholesale electricity to calculate direct access credits. After the PX closed in January 2001, direct access credits have been calculated based on the electricity 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 approximately 3,982 GWh in 2001.

Revenue passed through to the DWR decreased by approximately $117 million, or 5%, in 2002 from 2001. This decrease was mainly due to a decrease in our net open position, which resulted in less DWR electricity being delivered to our customers. The decrease in our net open position was caused by increases in the number of direct access customers and in the amount of electricity we were able to purchase from qualifying facilities due to renegotiated payment terms. In addition, we accrued approximately $369 million in additional pass through revenues to the DWR in 2002 due to changes proposed by the DWR to the methodology used to calculate DWR remittances. Absent this accrual, the decrease in the revenue passed through to the DWR would have been greater.

We will no longer collect the frozen rates and surcharges that we collected in 2003, 2002 and 2001 after the implementation of the rate design settlement. Instead, revenues in 2004 will be based on an aggregation of individual rate components, including base revenue requirements, electricity procurement costs and the DWR revenue requirement, among others. Changes in the DWR revenue requirements will change rates charged to certain of our customers. As a result, changes in amounts passed through to the DWR will no longer affect our results of operations. The rate design settlement will reduce electricity rates by approximately 8.0%, on average, and result in a reduction of electricity operating revenues of approximately $799 million.

Cost of Electricity

Our cost of electricity includes electricity purchase costs and the cost of fuel used by our owned generation facilities but it excludes costs to operate our generation facilities. The following table shows a breakdown of our cost of electricity and the total amount and average cost of purchased power, excluding, in each case, both the cost and volume of electricity provided by the DWR to our customers:

	2003	**2002**	**2001**
		(costs, except averages, in millions)	
Cost of purchased power	$ 2,449	$ 1,980	$ 3,224
Proceeds from surplus sales allocated to us	(247)		
Fuel used in owned generation	117	97	102
Adjustments to purchased power accruals		(595)	(552)
Total net cost of electricity	$ 2,319	$ 1,482	$ 2,774
Average cost of purchased power per kWh	$ 0.076	$ 0.081	$ 0.143
Total purchased power (GWh)	32,249	24,552	22,592

In 2003, our cost of electricity increased approximately $837 million, or 56%, compared to 2002 mainly due to the following factors:

Our total volume of electricity purchased in 2003 increased 31% because we resumed buying and selling electricity on the open market beginning in the first quarter of 2003 to meet our residual net open position in accordance with our CPUC-approved electricity procurement plan.

The increase in total costs was partially offset by proceeds from surplus electricity sales. We are required to dispatch all of the electricity resources within our portfolio, including electricity provided under DWR contracts, in the most cost-effective way. This requirement, in certain cases, requires us to schedule more electricity than is necessary to meet our retail load and to sell this additional electricity on the open market. We typically schedule this excess electricity when the expected sales proceeds exceed the variable costs to operate a generation facility or buy electricity on an optional contract. 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.

In March 2002, we recorded a net reduction of approximately $595 million to the cost of electricity as a result of FERC and CPUC decisions that allowed us to reverse previously accrued Independent System Operator, or ISO, charges and to adjust for the amount previously accrued as payable to the DWR for its 2001 revenue requirement. There was no comparable reduction in 2003.

In 2002, our cost of electricity decreased approximately $1.3 billion, or 47%, compared to 2001 because our average cost of purchased power decreased compared to 2001 mainly due to the significantly lower prices for electricity after the energy market stabilized in the second half of 2001. In addition, the DWR purchased all of the electricity needed to meet our net open position for all of 2002, whereas in 2001 we purchased the electricity ourselves through the PX market through the first half of January 2001.

In 2002, FERC and CPUC decisions allowed us to reverse previously accrued ISO charges and adjust previously accrued DWR pass-through revenues, reducing the cost of electricity by a net of approximately $595 million. In 2001, we recorded approximately $552 million for the market value of terminated bilateral contracts, reducing the cost of electricity by approximately $552 million for that year. The net effect of these adjustments contributed to an additional decrease of approximately $43 million in the cost of electricity in 2002.

Our cost of electricity in 2004 will be dependent upon electricity prices and our residual net open position.

Natural Gas Operating Revenues

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

	2003	2002	2001
	(revenues, except averages, in millions)		
Bundled natural gas revenues	$2,572	$2,020	$2,761
Transportation service-only revenues	284	316	375
Total natural gas operating revenues	$2,856	$2,336	$3,136
Average bundled revenue per Mcf of natural gas sold	$ 9.22	$ 7.16	$10.19
Total bundled natural gas sales (in Bcf)	279	282	271

In 2003, our total natural gas operating revenues increased approximately $520 million, or 22%, compared to 2002 mainly due to the following factors:

Bundled natural gas revenues increased by approximately $552 million, or 27%, in 2003 from 2002 mainly due to a higher average cost of natural gas, which we are permitted by the CPUC to pass on to our customers through higher rates. The average bundled revenue per Mcf of natural gas sold in 2003

increased $2.06, or 29%, compared to 2002. Natural gas prices increased in 2003 mainly due to a shortage in natural gas supply and lower storage reserves.

Transportation service-only revenues decreased by approximately $32 million, or 10%, in 2003 from 2002 mainly due to a decrease in demand for natural gas transportation services by certain noncore customers, mainly natural gas-fired electric generators in California. An increase in electricity available from hydroelectric facilities and the greater efficiency of generation facilities that commenced operations in 2003 resulted in reduced demand for natural gas transportation services.

In 2002, our total natural gas operating revenues decreased approximately $800 million, or 26%, compared to 2001 mainly due to the following factors:

Bundled natural gas revenues decreased by approximately $741 million, or 27%, in 2002 from 2001 mainly due to a lower average cost of natural gas. The average bundled revenue per Mcf of natural gas sold in 2002 decreased $3.03, or 30%, compared to 2001. Natural gas prices decreased in 2002 mainly due to an overall increase in natural gas supply and higher storage reserves.

Transportation service-only revenue decreased by approximately $59 million, or 16%, in 2002 from 2001 mainly due to a decrease in demand for gas transportation services by natural gas-fired electric generators in California.

Our natural gas revenues in 2004 are expected to increase due to natural gas distribution rate increases in the general rate case settlement and will be further impacted by changes in the cost of natural gas.

Cost of Natural Gas

Our cost of natural gas includes the purchase cost of natural gas and transportation costs on interstate pipelines, but excludes the costs associated with our intrastate pipeline, which are included in operating and maintenance expense. The following table shows a breakdown of our cost of natural gas:

	2003	2002	2001
	(costs, except averages, in millions)		
Cost of natural gas sold	$1,336	$ 853	$1,593
Cost of natural gas transportation	131	101	239
Total cost of natural gas	$1,467	$ 954	$1,832
Average cost per Mcf of natural gas sold	$ 4.79	$3.02	$ 5.88
Total natural gas sold (in Bcf)	279	282	271

In 2003, our total cost of natural gas sold increased approximately $513 million, or 54%, compared to 2002 mainly due to the following factors:

Our cost of natural gas sold increased approximately $483 million, or 57%, in 2003 from 2002 mainly due to an increase in the average cost of natural gas sold in 2003 of $1.77 per Mcf, or 59%.

Our cost of natural gas transportation increased by approximately $30 million, or 30%, in 2003 from 2002 mainly due to pipeline transportation charges paid to El Paso. We, along with other California utilities, were ordered by the CPUC in July 2002 to enter into new long-term contracts to purchase firm transportation services on the El Paso pipeline, under which we pay a fixed amount to secure capacity on the El Paso pipeline.

In 2002, our total cost of natural gas sold decreased approximately $878 million, or 48%, compared to 2001 mainly due to the following factors:

Our cost of natural gas sold decreased by approximately $740 million, or 46%, in 2002 from 2001 mainly due to a decrease of $2.86 per Mcf, or 49%, in the average cost of natural gas sold.

Our cost of natural gas transportation decreased by approximately $138 million, or 58%, in 2002 from 2001 mainly due to approximately $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.

Our cost of natural gas sold in 2004 will be affected by the prevailing costs of natural gas, which are determined by North American regions that supply us.

Operating and Maintenance

Operating and maintenance expenses consist mainly of our costs to operate our electricity and natural gas facilities, maintenance expenses, customer accounts and service expenses, administrative and general expenses, and the net deferral of revenues and expenses based on the difference between certain revenues and expenses recognized under GAAP and those revenues and expenses recognized for regulatory purposes.

In 2003, our operating and maintenance expenses increased approximately $118 million, or 4%, compared to 2002 mainly due to a reversal of a liability of approximately $65 million for surcharge revenues in excess of ongoing procurement costs and half-cent surcharge revenue collections at the end of 2002. The remainder of the increase was mainly due to wage increases in 2003 and increases in employee benefit plan-related expenses due to a 15% decrease in returns on plan investments and a decrease in the discount rates used to calculate the present value of our benefit obligations from 6.75% to 6.25%.

These increases were partially offset by a net increase in deferred electricity transmission-related costs compared to 2002. Electricity transmission-related costs are included in the cost of electricity and consist mainly of charges imposed by the ISO for grid management services. To the extent we do not receive revenues sufficient to recover electricity transmission-related costs, the costs are deferred through a reduction of operating and maintenance expenses until recovered in rates.

In 2002, our operating and maintenance expenses increased approximately $432 million, or 18%, compared to 2001 mainly due to the following factors:

Employee benefit plan-related expenses increased approximately $115 million in 2002 from 2001 mainly due to a 7% decrease in returns on plan investments and lower interest rates, which caused a decrease in the discount rate used to calculate the present value of our benefit obligations.

Environmental related expenses increased approximately $54 million in 2002 from 2001 mainly due to an increase in third party liabilities.

Our new customer billing system, which was implemented at the end of 2002, increased customer accounts and service expenses by approximately $23 million, or 9%, in 2002 from 2001. The increased cost in 2002 resulted from pre-implementation testing, validation and training costs.

The net deferred electricity transmission-related costs increased approximately $142 million in 2002 from 2001.

We began deferring overcollected electricity revenue associated with the rate reduction bonds in 2002. Total deferred revenue was approximately $85 million in 2002.

Depreciation, Amortization and Decommissioning

In 2003, our depreciation, amortization and decommissioning expenses increased approximately $25 million, or 2%, compared to 2002 mainly due to an overall increase in our plant assets.

In 2002, our depreciation, amortization and decommissioning expenses increased approximately $297 million, or 33%, compared to 2001 mainly due to the amortization of approximately $290 million of the rate reduction bond regulatory asset that began in January 2002.

Reorganization Fees and Expenses

In accordance with the American Institute of Certified Public Accountants Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code, or SOP 90-7, we report reorganization fees and expenses separately on our consolidated statements of operations. These costs mainly include professional fees for services in connection with our Chapter 11 proceedings and totaled approximately $160 million in 2003, $155 million in 2002 and $97 million in 2001. Upon implementation of our plan of reorganization and repayment in cash of substantially all allowed creditor claims and applicable interest and dividends, as discussed above, we will no longer incur reorganization fees and expenses.

Interest Income

In accordance with SOP 90-7, we report reorganization interest income separately on our Consolidated Statements of Operations. Reorganization interest income mainly includes interest earned on cash accumulated during our Chapter 11 proceedings. Interest income, including reorganization interest income, decreased approximately $21 million, or 28%, in 2003 from 2002 and approximately $49 million, or 40%, in 2002 from 2001. Decreases for both periods were mainly due to lower average interest rates earned on our short-term investments.

Interest Expense

In 2003, our interest expense decreased approximately $35 million, or 4%, compared to 2002 mainly due to the reduction in the amount of rate reduction bonds outstanding, reflecting the declining principal balance of the rate reduction bonds and a lower amount of unpaid debts accruing interest. This decrease was partially offset by the recording of approximately $38 million interest payable to the DWR in 2003 based upon a CPUC decision issued in January 2004. The interest payable to the DWR compensates the DWR for prior underpayments resulting from ambiguities in the formula that determined the DWR remittance rate that were resolved in September 2003. We have filed an application for rehearing of this decision with the CPUC.

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

As discussed above, our ongoing interest expense will be dependent upon the size of the refinancing and associated rates established at the effective date of our plan of reorganization.

Liquidity and Financial Resources

Overview

At December 31, 2003, our cash and cash equivalents balance was approximately $3.4 billion, of which approximately $403 million was restricted. The principal source of our cash is payments from our customers. Since wholesale electricity prices moderated and electricity surcharges were fully implemented in mid-2001, the cash generated by our operations has exceeded our ongoing cash requirements. We primarily invest our cash in money market funds and in short-term obligations of the U.S. Government and its agencies.

During our Chapter 11 proceeding, we have not had access to the capital markets and have met all our ongoing cash requirements, including our capital expenditures requirements, with cash generated by our operations. In addition, we have paid interest on certain pre-petition liabilities and repaid the principal of maturing mortgage bonds with bankruptcy court approval. We expect to pay allowed creditor claims from the proceeds of a public offering of a significant portion of the senior bonds, cash on hand and draws on credit and accounts receivable facilities established in connection with the implementation of our plan of reorganization. We also will establish an escrow account for disputed claims and deposit cash into these accounts to pay the claims as they are resolved.

Of our cash and cash equivalents at December 31, 2003, approximately $403 million is restricted as to its use. The restrictions arise from deposits under certain third party agreements, amounts held in escrow as collateral required by the ISO and deposits securing workers compensation obligations.

After the effective date of our plan of reorganization, we expect to fund our operating expenses and capital expenditures program from internally generated funds. We will maintain revolving credit, letter of credit, accounts receivable and other short-term borrowing facilities in order to provide sufficient liquidity to fund seasonal changes in working capital, balancing account undercollections, and credit support for collateralized procurement activities. We also expect to utilize a portion of our internally generated funds to make scheduled debt service payments and to achieve and maintain the target capital structure provided in the settlement agreement by the second half of 2005. Once we reach this target capital structure, we will commence distributions to Corp in the form of dividends and stock repurchases. Thereafter, a small portion of our capital expenditures program is expected to be funded with the issuance of new debt securities.

Operating Activities

Our cash flows from operating activities consist of monthly sales to our customers and operating expenses, other than expenses such as depreciation that do not require the use of cash. Cash flows from operating activities are also impacted by collections of accounts receivable and payments of liabilities previously recorded.

Our cash flows from operating activities for 2003, 2002 and 2001 were as follows:

	2003	2002	2001
		(in millions)	
Net income	$ 923	$ 1,819	$ 1,015
Non-cash (income) expenses:			
Depreciation, amortization and decommissioning	1,218	1,193	896
Net reversal of ISO accrual		(970)	
Change in accounts receivable	(590)	212	105
Change in accrued taxes	48	(345)	1,415
Other uses of cash:			
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(87)	(1,442)	(16)
Other changes in operating assets and liabilities	458	667	1,350
Net cash provided by operating activities	$ 1,970	$ 1,134	$ 4,765

Although net income decreased by approximately $896 million in 2003 compared to 2002, in 2003, net cash provided by operating activities increased by approximately $836 million compared to 2002 mainly due to the following factors:

Payments on amounts classified as liabilities subject to compromise decreased by approximately $1.3 billion in 2003, compared to 2002 due to significant pre-petition and post-petition payments made in 2002 under bankruptcy court-approved settlements.

Net cash provided by operating activities was partially offset by an increase in accounts receivable. This increase was mainly due to the settlement in 2003 of an amount payable to the DWR that was recorded as an offset to our customer accounts receivable balance in 2002. Amounts payable to the DWR are offset against amounts receivable from our customers for energy supplied by the DWR reflecting our role as a billing and collection agent for the DWR s sales to our customers.

Net income in 2002 included a non-cash reduction of approximately $970 million to cost of electricity related to the reversal of ISO charges.

In 2002, the net cash provided by operating activities decreased by approximately $3.6 billion compared to 2001, mainly due to the following factors:

Our filing of our Chapter 11 petition in April 2001 automatically stayed all payments on then-existing liabilities. After the filing, we resumed paying our ongoing expenses in the ordinary course of business. As a result, the growth in accounts payable was approximately $1.1 billion lower in 2002 than in 2001.

We received an approximately $1.1 billion income tax refund in 2001 and no comparable refund was received in 2002.

In 2002, we repaid approximately $901 million in pre-petition liabilities owed to qualifying facilities under bankruptcy court-approved agreements.

In 2002, under a bankruptcy court order, we paid approximately $1.0 billion in pre-petition and post-petition interest to holders of certain undisputed claims, trade creditors and certain other general unsecured creditors. These interest payments included approximately $433 million of accrued interest on financial debt previously classified as liabilities subject to compromise.

We will maintain revolving credit, letter of credit, accounts receivable and other short-term borrowing facilities in order to provide sufficient liquidity to fund seasonal changes in working capital, balancing account undercollections and credit support for collateralized procurement activities.

Investing Activities

Our investing activities consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to our customers. Cash flows from operating activities have been sufficient to fund our capital expenditure requirements during 2003, 2002 and 2001. Year to year variances depend upon the amount and type of construction activities, which can be influenced by storm and other damage.

Our cash flows from investing activities for 2003, 2002 and 2001 were as follows:

	2003	**2002**	**2001**
		(in millions)	
Capital expenditures	$(1,698)	$(1,546)	$(1,343)
Net proceeds from sale of assets	49	11	
Other investing activities, net	(114)	26	5
Net cash used by investing activities	$(1,763)	$(1,509)	$(1,338)

In 2003, net cash used by investing activities increased by approximately $254 million compared to 2002. This increase was mainly due to an increase in capital expenditures related to electricity transmission network upgrades and new electricity capacity and transmission development projects in 2003 and other investing activities during 2003. Cash flows from other investing activities related mainly to nuclear decommissioning funding and the change in nuclear fuel inventory during the period.

In 2002, net cash used by investing activities increased by approximately $171 million compared to 2001 mainly due to an increase in capital expenditures related to electricity transmission substation and line improvements intended to improve system reliability.

Financing Activities

During our Chapter 11 proceeding, our financing activities have been limited to repayment of secured debt obligations as authorized by the bankruptcy court. During this period, we have not had access to the capital markets. As discussed below, we expect to issue significant amounts of debt in connection with the implementation of our plan of reorganization and establish revolving credit and accounts receivable facilities to provide additional liquidity at and after the effective date of our plan of reorganization.

25

Our cash flows from financing activities for 2003, 2002 and 2001 were as follows:

	2003	2002	2001
		(in millions)	
Net repayments under credit facilities and short-term borrowings	$	$	$ (28)
Net long-term debt, matured, redeemed or repurchased	(281)	(333)	(111)
Rate reduction bonds matured	(290)	(290)	(290)
Other financing activities, net			(1)
Net cash used by financing activities	$ (571)	$ (623)	$ (430)

In 2003, net cash used by financing activities decreased by approximately $52 million compared to 2002. With bankruptcy court approval, we repaid approximately $281 million in principal on our mortgage bonds that matured in August 2003. PG&E Funding, LLC, our wholly owned subsidiary, also repaid approximately $290 million in principal on its rate reduction bonds. The rate reduction bonds are not included in our Chapter 11 proceeding. PG&E Funding, LLC pays the principal and interest on the rate reduction bonds from a specific rate element in our customers bills. We remit the collection of these billings to PG&E Funding, LLC on a daily basis.

In 2002, net cash used by financing activities increased by approximately $193 million compared to 2001. With bankruptcy court approval, we repaid approximately $333 million in principal on our mortgage bonds that matured in March 2002. PG&E Funding, LLC also repaid approximately $290 million in principal on its rate reduction bonds during each of 2001 and 2002.

Financing activities used approximately $430 million of net cash in 2001 mainly for repayments of long-term debt and rate reduction bonds. The repayment of long-term debt included payments of approximately $18 million on medium-term notes and approximately $93 million for mortgage bonds before our Chapter 11 filing.

Future Liquidity

After the effective date of our plan of reorganization, we expect to fund our operating expenses and capital expenditures substantially from internally generated funds, although we may issue debt for these purposes in the future. In addition, on or about the effective date of our plan of reorganization, we expect to establish new credit and accounts receivable facilities. We currently anticipate establishing a three-year revolving credit facility of approximately $850 million to $1.1 billion and an accounts receivable facility of approximately $600 million to $750 million. 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 paying a small portion of the allowed claims under our plan of reorganization. We also expect to establish a $650 million letter of credit facility that will be used to provide credit support for $614 million of reinstated pollution control bond-related obligations. We may also obtain bridge financings that will allow us to reissue or remarket at a later date up to approximately $800 million in pollution control bonds that we will not be able to reinstate at the effective date of our plan of reorganization.

We expect that the cash we will retain after the effective date of our plan of reorganization, together with cash from operating activities and available under the credit facilities we expect to establish, as described above, will provide for seasonal fluctuations in cash requirements and will be sufficient to fund our operations and our capital expenditures for the foreseeable future.

Dividend Policy

We have not declared or paid any common or preferred dividends in 2003, 2002 or 2001. While in Chapter 11, we are prohibited from paying any common or preferred dividends without bankruptcy court approval. Among other restrictions, we must maintain a capital structure authorized by the CPUC. We expect to achieve the target capital structure provided in the settlement agreement by the second half of 2005.

Capital Expenditures and Commitments

The following table provides information about our contractual obligations and commitments at December 31, 2003. This table includes obligations based on their existing terms. We expect to repay some of these obligations on, or as soon as practicable after, the effective date of our plan of reorganization. This table does not include payments on the senior bonds and credit facilities we expect to establish, in connection with our plan of reorganization.

	Payments due by period				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
	(in millions)				
Off Balance Sheet Commitments:					
Power purchase agreements(1):					
Qualifying facilities	$19,960	$1,590	$3,090	$2,880	$12,400
Irrigation district and water agencies	624	69	118	113	324
Other power purchase agreements	435	96	126	85	128
Natural gas supply and transportation	1,000	852	141	7	
Nuclear fuel	194	90	25	27	52
Other commitments(2)	238	126	78	29	5
Employee benefits:					
Pension(3)	386	129	257		
Postretirement benefits other than pension(3)	194	65	129		
Total off balance sheet commitments	23,031	3,017	3,964	3,141	12,909
Long-term debt:					
Liabilities not subject to compromise:					
Fixed rate principal obligations	2,741	310	289		2,142
Liabilities subject to compromise:					
Fixed rate principal obligations	1,184	225	697	1	261
7.90% Deferrable Interest Subordinated Debentures	300				300
Variable rate principal obligations	614	349	265		
Rate reduction bonds	1,160	290	580	290	
Preferred dividends and redemption requirements(4)	198	41	31	79	47

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

(2) Includes commitments for operating lease agreements mostly for office space in the aggregate amount of approximately $91 million, capital infusion agreements for limited partnership interests in the aggregate amount of approximately $16 million, contracts to retrofit generation equipment at our facilities in the aggregate amount of approximately $62 million, load-control and self-generation CPUC initiatives in the aggregate amount of approximately $35 million, contracts for local and long-distance telecommunications and other software in the aggregate amount of $16 million and capital expenditures for which we have contractual obligations or firm commitments

(3) Contribution estimates conform to forecasted amounts in the pending 2003 general rate case. Actual contributions are dependent upon the outcome of the 2003 general rate case. Contribution estimates after 2006 are subject to future general rate case test years.

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

Contractual Commitments

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

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 a qualifying facility s actual electricity output and CPUC-approved energy prices, while capacity payments are based on a qualifying facility s total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the qualifying facility fails to meet or exceeds performance requirements specified in the applicable power purchase agreement. Our capacity payments to qualifying facilities total approximately $500 million annually. Energy payments under power purchase agreements with qualifying facilities are typically based upon a CPUC-approved short-run avoided cost that is currently indexed to natural gas prices. Avoided costs are the incremental costs that an electric utility would incur to generate or purchase electricity but for the purchase from the qualifying facilities. As a result of the California energy crisis and our Chapter 11 filing, in July 2001, 197 qualifying facilities amended their contracts to fix their energy payments at $0.054 per kWh through July 2006. The remaining qualifying facility contracts calculate payment based on short-run avoided cost. Beginning in August 2006, the energy payments under all qualifying facility contracts will revert back to the short-run avoided cost rates.

At December 31, 2003, we had qualifying facility power purchase agreements with approximately 300 qualifying facilities for approximately 4,400 MW in operation. Agreements for approximately 4,000 MW expire between 2004 and 2028. Qualifying facility power purchase agreements for approximately 400 MW have no specific expiration dates and will terminate only when the owner of the qualifying facility exercises its termination option. On January 22, 2004, the CPUC adopted a decision that requires California investor-owned electric utilities to allow owners of qualifying facilities with power purchase agreements expiring before the end of 2005 to extend these contracts for five years. Qualifying facility power purchase agreements accounted for approximately 20% of our 2003 electricity sources, approximately 25% of our 2002 electricity sources and approximately 21% of our 2001 electricity sources. No single qualifying facility power purchase agreement accounted for more than 5% of our electricity sources during any of these periods.

In a proceeding pending at the CPUC, we have requested refunds in excess of $500 million for overpayments from June 2000 through March 2001 made to qualifying facilities. Under the settlement agreement, the net after-tax amount of any qualifying facility refunds that we actually realize in cash, claim offsets or other credits would reduce the $2.21 billion after-tax regulatory asset. While we are unable to estimate the outcome of this proceeding, we believe the proceeding will not have a material adverse effect on our financial condition or results of operations.

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 and variable payments for operating and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. Our irrigation district and water agency contracts accounted for approximately 5% of our 2003 electricity sources, approximately 4% of our 2002 electricity sources and approximately 3% of our 2001 electricity sources.

Other Power Purchase Agreements

Electricity Purchases to Satisfy the Residual Net Open Position. On January 1, 2003, we resumed buying electricity to meet our residual net open position. During 2003, more than 14,000 GWh of energy were bought and sold in the wholesale market to manage the 2003 residual net open position. Most of our contracts entered into in 2003 had terms of less than one year. During 2004, we plan to enter into contracts of longer duration to satisfy our near-term residual net open position.

Renewable Energy Requirement. California law requires that, beginning in 2003, each California investor-owned electric utility increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2017. We met our 2003 commitment and the CPUC has approved 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. At December 31, 2003, we had a $10 million collateralized standby letter of credit and a pledge of our core natural gas customer accounts receivable for the purpose of securing the purchase of natural gas. We replaced the pledge of the natural gas customer accounts receivable and natural gas inventory with $400 million of letters of credit in March 2004.

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 demand charges that we will pay each year may change periodically as a result of changes in regulated tariff rates. The total demand, net of sales of excess supplies, and volumetric transportation charges we incurred under these agreements were approximately $131 million in 2003, $101 million in 2002 and $239 million in 2001.

Nuclear Fuel Agreements

We have purchase agreements for nuclear fuel. These agreements have terms ranging from two to five years and are intended to ensure long-term fuel supply. These agreements are with a number of large, well-established international producers of nuclear fuel in order to diversify our commitments and provide security of supply. Pricing terms are also diversified, ranging from fixed prices to base prices that are adjusted using published information. Deliveries provided under nine of the eleven contracts in place at the end of 2003 will end by 2005. In most cases, our nuclear fuel agreements are requirements-based. Payments for nuclear fuel amounted to approximately $57 million in 2003, $70 million in 2002 and $50 million in 2001.

Western Area Power Administration Commitments

In 1967, we and the Western Area Power Administration, or WAPA, entered into several long-term power contracts governing the interconnection of our respective electricity transmission systems, the use of our electricity transmission and distribution systems by WAPA, and the integration of our respective customer demands and electricity 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. The contracts are scheduled to terminate on December 31, 2004. Termination is subject to FERC approval, which we expect to receive.

The contractual commitments table above does not include our WAPA commitment because the costs to fulfill our obligations to WAPA cannot be accurately estimated at this time. Both the purchase price and the amount of electricity WAPA will need from us in 2004 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, including DWR power and bond charges and after subtracting revenues received from WAPA, for electricity delivered under the contracts were approximately $233 million in 2003, $127 million in 2002 and $350 million in 2001.

Transmission Control Agreement

We are a party to a Transmission Control Agreement, or TCA, with the ISO and other participating transmission owners. As a transmission owner, we are required to give two years notice and receive regulatory approval if we wish to withdraw from the TCA. Under this agreement, the transmission owners, which also include Southern California Edison, or SCE, San Diego Gas & Electric Company and several municipal utilities, assign operational control of their electricity transmission systems to the ISO. In addition, as a party to the TCA, we are responsible for a share of the costs of reliability must-run, or RMR, agreements between the ISO and owners of the power plants subject to RMR agreements, or RMR plants. We are also an owner of some of these RMR plants for which we receive revenue from the ISO. Under the RMR agreements, RMR plants must remain available to generate electricity when needed for local transmission system reliability upon the ISO s demand.

At December 31, 2003, the ISO had RMR agreements for which we could be obligated to pay the ISO an estimated $446 million in net costs during the period January 1, 2004 to December 31, 2005. These costs are recoverable under applicable ratemaking mechanisms.

It is possible that we may receive a refund of RMR 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 Corporation, or Mirant, that are parties to three RMR agreements with the ISO to refund to the ISO, and the ISO to refund to us, excess payments of approximately $340 million, including interest, for availability of Mirant s RMR plants under these agreements. On July 14, 2003, Mirant filed a petition for reorganization under Chapter 11 and on December 15, 2003, we filed claims in Mirant s Chapter 11 proceeding including a claim for an RMR refund. 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. It is uncertain how the resolution of this matter would be reflected in rates.

Other Commitments

We have other commitments relating to operating leases, capital infusion agreements, equipment replacements, software licenses, the self-generation incentive program exchange agreements and telecommunication contracts.

At December 31, 2003, the future minimum payments related to other commitments were as follows:

	(in millions)
2004	$126
2005	48
2006	30
2007	15
2008	14
Thereafter	5
Total	$238

Financing 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, substantially all of which are pre-petition obligations. On the effective date of our plan of reorganization, we expect to reinstate certain pollution control bond-related obligations in the amount of approximately $814 million. The balance of the pre-petition obligations will be paid in full in cash, plus applicable interest, on or as soon as practicable after the effective date of our plan of reorganization. After the effective date, our obligations also will include, in addition to the reinstated pollution control bond-related

obligations, the amount of senior bonds that we sell and the credit and accounts receivable facilities that we establish in connection with the implementation of our plan of reorganization.

In addition, PG&E Funding, LLC must make scheduled payments on its rate reduction bonds. The balance owed on these bonds at December 31, 2003 was approximately $1.16 billion. Annual principal payments on the rate reduction bonds total approximately $290 million. The rate reduction bonds are expected to be fully retired by the end of 2007.

Capital Expenditures

Our investment in plant and equipment totaled approximately $1.7 billion in 2003, $1.5 billion in 2002 and $1.3 billion in 2001.

The following table reflects our estimated capital expenditures for the next five years. Capital expenditures for which contracts or firm commitments exist have, in addition to being included in the table below, been included in the table above, which details our contractual obligations and commitments at December 31, 2003.

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

Our significant capital expenditure projects include:

- new customer connections and expansion of the existing electricity and natural gas distribution systems anticipated to average approximately $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 electricity transmission system expected to average approximately $260 million annually over the next five years;

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

The discussion above does not include any capital expenditures for new generation facilities. The residual net open position is expected to increase over time. To meet this need, we will need to enter into contracts with third-party generators for additional supplies of electricity, develop or otherwise acquire additional generation

31

facilities or satisfy our residual net open position through a combination of contracts and additional generation facilities. The discussion above also does not include any capital expenditures necessary to implement advanced metering improvements.

Contingencies

Surcharge Revenues

In January 2001, the CPUC authorized increases in electricity rates of $0.01 per kWh, in March 2001 of another $0.03 per kWh and in May 2001 of 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 the surcharges to be used to restore our financial health by permitting us to record amounts related to the surcharge revenues as an offset to unrecovered transition costs. From January 2001 to December 31, 2003, we recognized total surcharge revenues of approximately $8.1 billion, pre-tax. The rate design settlement included a refund of approximately $125 million of surcharge revenues. We recorded a regulatory liability for the potential refund of approximately $125 million of surcharge revenues collected during 2003, which is reflected on our balance sheet at December 31, 2003. If the CPUC requires us to refund any amounts in excess of approximately $125 million, our earnings could be materially adversely affected.

Advanced Metering Improvements

The CPUC is assessing the viability of implementing an advanced metering infrastructure for residential and small commercial customers. This infrastructure would enable the California investor-owned electric utilities to measure usage of electricity on a time-of-use basis and to charge demand responsive rates. The goal of demand responsive rates is to encourage customers to reduce energy consumption during peak demand periods and thereby reduce peak period procurement costs. Advanced meters can record usage in time intervals and be read remotely. We are implementing demand responsive tariffs for large industrial customers who already have advanced metering systems in place, and a statewide pilot program is in progress to test whether and to what extent residential and small commercial customers will respond to demand responsive 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 our customers. We would expect to recover through rates the capital investments and any ongoing operating costs associated with implementing the advanced metering improvements. The total deployment of an advanced metering infrastructure to all of our electricity and natural gas customers using equipment and technology currently available may cost more than $1.0 billion (in 2003 dollars), based on a five-year installation schedule starting in 2005.

El Paso Settlement

In June 2003, we, along with a number of other parties, 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, El Paso will pay $1.5 billion in cash and non-cash consideration, of which approximately $550 million is now in an escrow account and approximately $875 million will be paid over 15 to 20 years. Our share of the $1.5 billion settlement is approximately $300 million. El Paso also agreed to a $125 million reduction in El Paso s long-term electricity supply contracts with the DWR, to provide pipeline capacity to California and to ensure specific reserve capacity for us, if needed. In October 2003, the CPUC approved an allocation of these refunds, under which our natural gas customers would receive approximately $80 million and our electricity customers would receive approximately $216 million. The settlement was approved by the FERC in November 2003 and by the San Diego Superior Court in December 2003. At least one appeal of the San Diego Superior Court s approval has been filed; however, we believe that it is probable that the El Paso settlement will not be overturned on appeal. Our proposed electricity rate reduction in 2004, filed with the CPUC on January 26, 2004, included a reduction of $79 million to the $2.21 billion after-tax regulatory asset related to this El Paso settlement. In December 2003, we also proposed a gas rate reduction related to this El Paso settlement of $29 million to be implemented in 2004.

Enron Settlement

On December 23, 2003, we entered into a settlement agreement with five subsidiaries of Enron Corporation, or Enron, settling certain claims between us and Enron, or the Enron settlement. The Enron settlement will become effective if approved by the bankruptcy courts overseeing both our and Enron s Chapter 11 proceedings. A hearing for approval of the Enron settlement is currently scheduled in our Chapter 11 proceeding on March 5, 2004. A hearing was held in the Enron bankruptcy court on February 5, 2004 and the matter was submitted. Various parties have opposed the settlement in our and Enron s Chapter 11 proceedings. If the Enron settlement is approved, we will receive an after-tax credit of approximately $90 million that will reduce the $2.21 billion after-tax regulatory asset provided for in the settlement agreement. In the rate design settlement approved by the CPUC on February 26, 2004, our revenue requirement related to the amortization of the $2.21 billion after-tax regulatory asset has been reduced to reflect the proposed settlement. The CPUC decision approving the rate design settlement provides for regulatory balancing account treatment to ensure that the amount of the revenue requirement reduction is adjusted to reflect the amounts actually received by us under pending settlements with energy suppliers, including Enron.

DWR Contracts

The DWR provided approximately 30% of the electricity delivered to our customers for the year ended December 31, 2003. The DWR purchased the electricity under contracts with various generators and through open market purchases. We are responsible for administration and dispatch of the DWR s electricity procurement contracts allocated to our customers, for purposes of meeting a portion of our net open position. The DWR remains legally and financially responsible for its electricity procurement contracts.

The DWR contracts terminate at various times through 2012 and consist of must-take and capacity charge contracts. Under must-take contracts, the DWR must take and pay for electricity generated by the applicable generating facility regardless of whether the electricity is needed. Under capacity charge contracts, the DWR must pay a capacity charge but is not required to purchase electricity unless that electricity is dispatched and delivered.

The DWR has stated publicly that it intends to transfer full legal title to, and responsibility for, the DWR power purchase contracts to the California investor-owned electric utilities as soon as possible. However, the DWR power purchase contracts cannot be transferred to us without the consent of the CPUC. The 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 power purchase 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 S&P will be no less than A;

- the CPUC first makes a finding that, for purposes of assignment or assumption, the DWR power purchase contracts to be 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 power purchase contracts to be assumed without further review.

Our Regulatory Environment

We are regulated primarily by the CPUC and the FERC. The FERC is an independent agency within the U.S. Department of Energy, or DOE, that, among other things, regulates the transmission of electricity and the sale for resale of electricity in interstate commerce. The CPUC has jurisdiction to, among other things, set the rates, terms and conditions of service for our electricity distribution, natural gas distribution and natural gas transportation and storage services in California.

Ratemaking

Rates

Transition from Frozen Rates to Cost of Service Ratemaking

Frozen electricity rates, which began on January 1, 1998, were designed to allow us to recover our authorized utility costs, and, to the extent frozen rates generated revenues in excess of these costs, to recover our transition costs. Although the surcharges implemented in 2001 effectively increased the actual rate under the frozen rate structure, increases in our authorized revenue requirements did not increase our revenues. In addition, DWR revenue requirements reduced our revenues under the frozen rate structure. As a result of revised electricity rates discussed below and a January 2004 CPUC decision determining that the rate freeze ended on January 18, 2001, we expect that once approved by the CPUC, our rates will reflect cost of service ratemaking and will be calculated based on the aggregate of various authorized rate components. Changes in any individual revenue requirement will change customers electricity rates.

On February 26, 2004, the CPUC approved the rate design settlement to implement an overall electricity rate reduction of approximately $799 million. Although actual rates will not be reflected in customers bills until March 1, 2004, or shortly thereafter, the rate reduction is retroactive to January 1, 2004. The revised rates and forecast revenue requirements are based on, and ultimately will be adjusted to reflect, pending or final CPUC decisions including:

our 2003 general rate case;

the allocation of the DWR s 2004 revenue requirements;

pending energy supplier refunds, claim offsets or other credits pursuant to the settlement agreement; and

the calculation of any overcollection of the surcharge revenues for 2003.

General Rate Case Settlement

The CPUC determines the amount of authorized base revenues we can collect from customers to recover our basic business and operational costs for electricity and natural gas distribution operations and for electricity generation operations in a general rate case. Our last general rate case was our 1999 general rate case, approved by the CPUC in 2000. The 2003 general rate case has been filed, testimony has been given before the CPUC and we are awaiting a final decision. Any revenue requirement change resulting from a final decision will be retroactive to January 1, 2003.

In July 2003, we and various intervenors (the CPUC s Office of Ratepayer Advocates, or ORA, TURN, Aglet Consumer Alliance, and the City and County of San Francisco) filed a joint motion with the CPUC seeking approval of a settlement agreement resolving specific issues related to the cost of operating our electricity generation facilities, or the generation settlement. In September 2003, we and various intervenors (ORA, TURN, Aglet Consumer Alliance, the Modesto Irrigation District, the Natural Resources Defense Council and the Agricultural Energy Consumers Association) filed a joint motion with the CPUC seeking approval of the general rate case settlement. The general rate case settlement, together with the generation settlement, resolves all disputed economic issues among the settling parties related to our electricity distribution, natural gas distribution and generation revenue requirements, 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. The CPUC agreed in the settlement agreement to act promptly on the 2003 general rate case.

The general rate case settlement would result in a total 2003 revenue requirement of approximately $2.5 billion for electricity distribution operations, representing an increase of approximately $236 million in our electricity distribution revenue requirement over the current authorized amount. The general rate case settlement provides that the electricity distribution rate base on which we would be entitled to earn an authorized rate of return would be approximately $7.7 billion, based on recorded 2002 plant, and including net weighted average capital additions for 2003 of approximately $292 million.

The general rate case settlement also would result in a total 2003 revenue requirement of approximately $927 million for our natural gas distribution operations, representing an increase of approximately $52 million in our natural gas distribution revenue requirement over the current authorized amount. The general 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 approximately $2.1 billion, based on recorded 2002 plant and including weighted average capital additions for 2003 of approximately $89 million.

Together with the generation settlement, the general rate case settlement would result in a 2003 generation revenue requirement of $912 million representing an increase of approximately $38 million in our generation revenue requirement over the current authorized amount. This generation revenue requirement excludes fuel expense, the cost of electricity purchases, the DWR revenue requirements and nuclear decommissioning revenue requirements. Under the settlement agreement, our adopted 2003 generation rate base of approximately $1.6 billion would be 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 would allow recognition of an after-tax regulatory asset of approximately $800 million (or approximately $1.3 billion pre-tax) as estimated at December 31, 2003. We expect to record this regulatory asset when it meets the probability requirements for regulatory recovery in rates as provided for in SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, or SFAS No. 71, as discussed above. The individual components of the regulatory asset will be amortized over their respective lives. The weighted average life of these individual components is approximately 16 years.

The general rate case settlement also provides for new balancing accounts to be established retroactive to January 1, 2004 that permit us to recover our authorized electricity distribution and generation revenue requirement regardless of the level of sales. If sales levels do not generate the full revenue requirement in a period, rates in subsequent periods will be increased to collect the shortfall. Similarly, future rates will decrease if sales levels generate more than the full revenue requirement.

If we prevail on the pension contribution issue, an additional revenue requirement of approximately $75 million would be allocated among electricity distribution, natural gas distribution and electricity generation operations.

Because the CPUC has yet to issue a final decision on our 2003 general rate case, we have not included the natural gas distribution revenue requirement increase in our 2003 results of operations. If the CPUC approves a 2003 revenue requirement increase in 2004, we would record both the 2003 and 2004 natural gas distribution revenue requirement increase in our 2004 results of operations.

In 2003 we collected electricity revenue and surcharges subject to refund under the frozen rate structure. The amount of electricity revenue subject to refund pursuant to the rate design settlement in 2003 was $125 million, which incorporates the impact of the electric portion of the general rate case settlement. We have recorded a regulatory liability for such amount. If the revenue requirement that is ultimately approved in our 2003 general rate case is lower than the amounts described above, the regulatory liability would increase.

The CPUC also is considering a proposed reliability performance incentive mechanism for us that would be in effect from 2004 through 2009. Under the proposed incentive mechanism, we would receive up to $27 million in additional annual revenues to be recorded in a one-way balancing account to be spent exclusively on reliability performance activities with a goal of decreasing the duration and frequency of electricity outages. We would be entitled to earn a maximum reward of up to $42 million each year depending on the extent to which we exceeded the reliability performance improvement targets. Conversely, we would be required to pay a penalty of up to $42 million a year depending on the extent to which we failed to meet the target.

On February 3, 2004, the CPUC reopened the 2003 general rate case record for the purpose of taking further evidence regarding executive compensation and bonuses. We have filed a report addressing these issues with the CPUC. We are uncertain how this matter will be resolved and when a final general rate case decision will be issued.

If the general rate case settlement is not approved by the CPUC, our ability to earn our authorized rate of return for the years until the next general rate case would be adversely affected. The parties to the general rate case settlement have agreed that our next general rate case will determine rates for test year 2007. We are unable to predict the outcome of the 2003 general rate case or the impact it will have on our financial condition or results of operations.

Attrition Rate Adjustments for 2004-2006

The general rate case settlement provides for yearly adjustments to our base revenues, or attrition increases, for the years 2004, 2005 and 2006. The attrition increase will be based upon the change in the consumer price index, or CPI, subject to certain minimums and maximums.

The following tables show the multiplier, and the minimum and maximum percentage change for each revenue requirement along with estimates of the minimum and maximum total electricity distribution, natural gas distribution and generation revenue requirements for the years that would be covered by the 2003 general rate case.

	2004	**2005**	**2006**
Minimum	2.00% Distribution	2.25% Distribution	3.00% Distribution
	1.50% Generation	1.50% Generation	2.50% Generation
Multiplier	Change in CPI	Change in CPI	Change in CPI + 1%
Maximum	3.00% Distribution	3.25% Distribution	4.00% Distribution
	3.00% Generation	3.00% Generation	4.00% Generation

	2003	**2004**	**2005**	**2006**
		(in billions)		
Electric Distribution Revenues	$2.493			
Minimum		$2.543	$2.600	$2.678
Maximum		2.568	2.651	2.757
Gas Distribution Revenues	0.927			
Minimum		0.946	0.967	0.996
Maximum		0.955	0.986	1.025
Generation Revenues (1)	0.912			
Minimum		0.926	0.940	0.963
Maximum		0.939	0.968	1.006

(1) Generation calculations exclude an approximately $32 million incremental attrition adjustment in 2004 to reflect the need for a second refueling outage at the Diablo Canyon power plant during that year.

Because these attrition adjustments are based on our current authorized capital structure and rate of return, they could be affected by future cost of capital proceedings. In addition, if we prevail on the pension contribution issue as discussed above, the attrition adjustments would be slightly higher to reflect the addition of approximately $75 million to our 2003 revenue requirements.

Cost of Capital Proceedings

Each year we must file an application with the CPUC to determine our authorized capital structure and the authorized rate of return we may earn on our electricity and natural gas distribution and electricity 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%. Our currently authorized capital structure is 48.00% common equity, 46.20% long-term debt and 5.80% preferred equity.

We must file a cost of capital application within 30 days after completing the financings to implement our plan of reorganization. For 2004, this cost of capital proceeding will also determine the authorized rate of return for natural gas transportation and storage. The application must reflect changes in capital structure, long-term debt and preferred stock costs and costs associated with interest rate hedges. The settlement agreement provides that from January 1, 2004 until Moody s has issued an issuer rating for us of not less than A3 or S&P 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 will be no less than 52%. However, for 2004 and 2005, our

36

authorized equity ratio will equal the greater of the proportion of equity approved in our 2004 and 2005 cost of capital proceedings and 48.6%.

DWR Revenue Requirements

The DWR filed a proposed $4.5 billion 2004 power charge revenue requirement and a proposed 2004 bond charge revenue requirement of approximately $873 million with the CPUC in September 2003. In January 2004, the CPUC issued a decision that adopted an interim allocation of the DWR s proposed 2004 revenue requirements among the three California investor-owned electric utilities. Our customers share of the DWR power charge revenue requirement is approximately $1.8 billion after consideration of the DWR 2001-2002 adjustment discussed below. The January 2004 decision allocated the bond charge revenue requirement among the three California investor-owned electric utilities on an equal cents per kWh basis, which resulted in approximately $369 million being allocated to our customers.

The CPUC will consider adopting a multi-year allocation of the DWR s power charge revenue requirements in a second phase of the 2004 DWR power charge proceeding. If adopted, a multi-year allocation would replace the interim allocation for 2004. We cannot predict the final outcome of this matter.

The DWR revenue requirements have been subject to various adjustments, including the reallocation of contracts among the California investor-owned electric utilities, adjustments to reflect actual deliveries and adjustments resulting from changes in allocation methodologies. In January 2004, the CPUC issued a decision finding that we had over-remitted approximately $101 million in power charges to the DWR related to the DWR s 2001-2002 revenue requirement and ordered that our allocation of the DWR s 2004 power charge revenue requirement be reduced by this amount.

As a result of the transition from frozen rates to cost of service ratemaking described above, the collection of DWR revenue requirements, or any adjustments to DWR revenue requirements, including the reduction in the DWR s 2004 revenue requirement related to 2001 through 2002, will not affect our results of operations.

Baseline Allowance Increase

In May 2002, the CPUC ordered the California investor-owned electric utilities to increase the baseline allowances for certain residential customers, which reduced our electricity revenues. An increase to a customer s baseline allowance is an increase to the amount of monthly usage that is covered under the lowest possible electricity rate and exempt from certain surcharges. The CPUC deferred consideration of corresponding rate changes until a later phase of the proceeding and ordered the California investor-owned electric utilities to track the undercollections associated with their respective baseline quantity changes in an interest-bearing balancing account. We are charging the electricity revenue-related shortfall against earnings because we cannot predict the outcome of the later phase of the proceeding, nor can we conclude that recovery of the electricity-related balancing account is probable. The total electricity revenue shortfall was approximately $70 million for the period from May through December 2002 and approximately $114 million for 2003. On February 26, 2004, the CPUC issued a decision which includes demographic revisions to the baseline program. These modifications increase annual electricity revenue shortfalls by approximately $12 million. The rate design settlement, approved by the CPUC on February 26, 2004, provides for timely rate adjustments for prospective revenue shortfalls resulting from the baseline program. The rate design settlement does not, however, provide for the recovery of shortfalls before the implementation of the rate design settlement.

Electricity Procurement

Our Electricity Procurement

Beginning January 1, 2003, we resumed responsibility for procuring electricity for our residual net open position. Our residual net open position is expected to grow over time for a number of reasons, including:

- Periodic expirations of existing electricity purchase contracts.

- Periodic expirations or other terminations of the DWR allocated contracts. For the period 2004-2009, the DWR must-take contracts and contracts with mandatory capacity payments are expected to supply about

25% of the electricity demands of our customers. For the period 2010-2012, the DWR must-take contracts and contracts with mandatory capacity payments are expected to supply less than 10% of the electricity demands of our customers.

Increases in our customers electricity demands due to customer and economic growth or other factors.

Retirement or closure of our electricity generation facilities.

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 electricity purchase contracts or the DWR allocated contracts, would immediately increase our residual net open position.

Effective January 1, 2003, under California law we established a balancing account, the Energy Resource Recovery Account, or ERRA, designed to track and allow recovery of the difference between the recorded procurement revenues and actual costs incurred under our authorized procurement plans, excluding the costs associated with the DWR allocated contracts and certain other items. The CPUC must review the revenues and costs associated with an investor-owned utility s electricity procurement plan at least semi-annually and adjust retail electricity rates or order refunds, as appropriate, when the aggregate overcollections or undercollections exceed 5% of the utility s prior year electricity procurement revenues, excluding amounts collected for the DWR. These mandatory adjustments will continue until January 1, 2006. The CPUC s review of our procurement activities will examine our least-cost dispatch of our resource portfolio (including the DWR allocated contracts), fuel expenses for our electricity generation facilities, contract administration (including administration of the DWR allocated contracts) and our electricity procurement contracts. As a result of this review, some of our procurement costs could be disallowed. We cannot predict whether a disallowance will occur or the size of any potential disallowance.

In January 2004, the CPUC adopted an interim decision that would require the California investor-owned electric utilities to achieve by January 1, 2008 an electricity reserve margin of 15-17% in excess of peak capacity electricity requirements and have a diverse portfolio of electricity sources. These requirements may increase our residual net open position. Specific procedures contained in the decision relating to development and execution of our procurement plans may also cause our cost of electricity to increase. The CPUC also continued its target of a 5% limitation on reliance by the California investor-owned electric utilities on the spot market to meet their energy needs.

In February 2004, we requested that the CPUC approve our 2004 ERRA revenue requirement of approximately $2.2 billion associated with our 2004 short-term procurement plan. Costs associated with electricity procurement contracts entered into prior to January 1, 2003, such as the qualifying facility contracts, are eligible for recovery under the ERRA provided the costs are under a CPUC authorized benchmark. The benchmark anticipated to be adopted by the CPUC for 2004 is $0.0518 per kWh, based upon a report prepared by the California Energy Commission, or CEC. The CPUC will establish a benchmark for each year of the ERRA. Determination of whether procurement costs associated with these contracts are within the benchmark is done on a portfolio basis including a hypothetical cost for our own generation facilities. Costs that are above the benchmark are recoverable as above-market generation and procurement costs. We have asked the CPUC to approve an additional proposed revenue requirement of approximately $150 million to recover the 2004 costs related to the above-market generation and procurement costs that exceed the CPUC-adopted benchmark discussed above.

On February 26, 2004, the CPUC approved revised rates based on our overall revenue requirements for 2004 included in a filing we made on January 26, 2004. If related filings are approved by the CPUC, the ERRA would track and allow recovery of the difference between actual ERRA revenues collected and actual costs incurred.

Although the CPUC has no authority to review the reasonableness of procurement costs in the DWR s contracts, it may review our administration of the DWR allocated contracts. We are required to dispatch our electricity resources, including the DWR allocated contracts, on a least-cost basis. The CPUC has established a maximum annual procurement disallowance for our administration of the DWR allocated contracts and least-cost dispatch of our electricity resources of two times our administration costs of managing procurement activities, or $36 million for 2003. Activities excluded from the maximum annual disallowance include fuel expenses for our electricity generation resources and contract administration costs associated with electricity procurement contracts, qualifying facility contracts and certain electricity generation expenses. In its decision approving our 2004 short-term procurement plan, the CPUC extended the application of this maximum disallowance amount to cover our 2004 procurement activities. It is uncertain whether the CPUC will modify or eliminate the maximum annual disallowance for future years.

FERC Prospective Price Mitigation Relief

Various entities, including the state of California and us, are seeking up to $8.9 billion in refunds on behalf of California electricity purchasers for electricity overcharges from January 2000 to June 2001. In December 2002, a FERC administrative law judge issued an initial decision finding that power suppliers overcharged the utilities, the state of California and other buyers approximately $1.8 billion from October 2, 2000 to June 20, 2001 (the only time period for which the FERC permitted refund claims), but that California buyers still owe the power suppliers approximately $3.0 billion, leaving approximately $1.2 billion in net unpaid bills.

During 2003, the FERC confirmed most of the administrative law judge s findings, but partially modified the refund methodology to include use of a new natural gas price methodology as the basis for mitigated prices. The FERC indicated that it would consider later allowances claimed by sellers for natural gas costs above the natural gas prices in the refund methodology. In addition, the FERC directed the ISO and the PX, which operates solely to reconcile remaining refund amounts owed, to make compliance filings establishing refund amounts by March 2004. The ISO has indicated that it plans to make its compliance filing by August 2004. The actual refunds will not be determined until the FERC issues a final decision following the ISO and PX compliance filings. The FERC is uncertain when it will issue a final decision in this proceeding. In addition, future refunds could increase or decrease as a result of an alternative calculation proposed by the ISO, which incorporates revised data provided by us and other entities.

Under the 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 and other energy suppliers relating to our ISO, PX, qualifying facilities or energy service provider costs that are actually realized in cash or by offset of creditor claims in our Chapter 11 proceeding would reduce the balance of the $2.21 billion after-tax regulatory asset created by the settlement agreement.

We have recorded approximately $1.8 billion of claims filed by various electricity generators in our Chapter 11 proceeding as liabilities subject to compromise. This amount is subject to a pre-petition offset of approximately $200 million, reducing the net liability recorded to approximately $1.6 billion. We currently estimate that the claims filed would have been reduced to approximately $1.2 billion based on the refund methodology recommended in the administrative law judge s initial decision, resulting in a net liability of approximately $1.0 billion after the approximately $200 million pre-petition offset. The recalculation of market prices according to the revised methodology adopted by the FERC in its October 2003 decision could further reduce the amount of the suppliers claims by several hundred million dollars. However, this reduction could be offset by the amount of any additional fuel cost allowance for suppliers if they demonstrate that natural gas prices were higher than the natural gas prices assumed in the refund methodology.

FERC Transmission Owner Rate Cases

On January 13, 2003, we filed an application with the FERC requesting authority to recover approximately $545 million in annual electricity transmission retail revenue requirements for 2003. The January 13, 2003 proposed rates went into effect, subject to refund, on August 13, 2003 and remained in effect through December 31, 2003. We have accrued approximately $26 million for potential refunds related to the period these rates were in effect.

We filed an additional rate application with the FERC at the end of October 2003 requesting recovery of approximately $530 million per year, subject to refund, in electricity transmission retail revenue requirements. We requested a 13.0% return on equity and recovery of the costs of providing safe and reliable transmission service during 2004. On December 30, 2003 the FERC accepted this proposed revenue requirement and related rates, subject to hearing and refund, effective as of January 1, 2004.

Natural Gas Supply and Transportation

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. On December 18, 2003, the CPUC approved our application to retain the gas accord market structure for 2004 and 2005 and resolved the rates, and terms and conditions of service for our natural gas transportation and storage system for 2004. The CPUC adopted a 2004 revenue requirement of $436.4 million, representing a $12.5 million increase from 2003.

In addition, the December 2003 CPUC decision exempts, beginning in 2005, certain customers connected to our backbone transportation facilities from paying local transportation rates and orders us to review and consider a backbone level rate structure, which may include a surcharge to recover what may otherwise be stranded costs resulting from departing local transmission customers. Our backbone transportation facilities connect natural gas transportation pipelines delivering natural gas from California s border and from California production and storage facilities to the local natural gas transportation system.

Under the gas accord market structure, we are at risk of not recovering our natural gas transportation and storage costs and do not have regulatory balancing account provisions for overcollections or undercollections of natural gas transportation or storage revenues. We may experience a material reduction in operating revenues if throughput levels or market conditions are significantly less favorable than reflected in rates for these services.

The gas accord also established an incentive mechanism for recovery of core procurement costs, or the CPIM, which is used to determine the reasonableness of our costs of purchasing natural gas for our customers. The December 2003 CPUC decision extended the CPIM with adjustments through 2005. 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 purchases natural gas. Costs that fall within a tolerance band, which is currently 99% to 102% of the benchmark, are considered reasonable and fully recoverable in customers rates. One-half of the costs above 102% of the benchmark are recoverable in our customers rates, and our customers receive three-fourths of the savings when the costs are below 99% of the benchmark.

On January 22, 2004, the CPUC opened a rulemaking to require California natural gas utilities to submit proposals aimed at ensuring reliable, long-term supplies of natural gas to California. The CPUC ordered us and other California natural gas utilities to submit proposals addressing how California s long-term natural gas needs should be met through contracts with interstate pipelines, new liquified natural gas facilities, storage facilities and in-state production of natural gas. This proceeding will be divided into two phases. Phase 1 will address utilities expiring contracts with interstate pipelines, the amount of interstate capacity the utilities should hold, the approval process for contracts with interstate pipelines and access to liquified natural gas facilities supplies. Phase 2 will examine broader long-term supply and capacity issues. We are unable to predict the outcome of this rulemaking or the impact it will have on our financial condition or results of operations.

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

In May 2003, 2002, 2001 and 2000, we filed our annual applications with the CPUC in the Annual Earnings Assessment Proceeding claiming incentives totaling approximately $106 million for energy efficiency program activities and public purpose programs. These applications remain subject to verification and approval by the CPUC. The CPUC has only authorized us to recognize an insignificant amount of these incentives in our consolidated statements of operations. There are a number of forward-looking proceedings regarding program administration and incentive mechanisms for energy efficiency. It is too early to predict whether the CPUC will allow us to continue administering energy efficiency programs and earning incentives based on the performance of the programs.

2001 Annual Transition Cost Proceeding: Review of Reasonableness of Electricity Procurement

In April 2003, the ORA issued a report regarding our procurement activities for the period July 1, 2000 through June 30, 2001, recommending that the CPUC disallow recovery of approximately $434 million of our procurement costs based on an allegation that our market purchases during the period were imprudent because we did not develop and execute a reasonable hedging strategy. The ORA recommendation does not take into account any FERC-ordered refunds of our procurement costs during this period, which could effectively reduce the amount of the recommended disallowance. In our response to the ORA s report, we indicated that the ORA recommendation is unlawful, contrary to prior CPUC decisions, and factually unsupported. Under the settlement agreement, the CPUC agreed to act promptly to resolve this proceeding, with no adverse impact on our cost recovery, as soon as practicable after our plan of reorganization becomes effective.

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. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

DWR Revenues

We act as a pass-through entity for electricity purchased by the DWR that is sold to our customers. Although charges for electricity provided by the DWR are included in the amounts we bill our customers, we deduct from electricity revenues 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, priced at the related CPUC-approved remittance rate. These pass-through amounts are excluded from our electricity revenues in our consolidated statements of operations. During 2003, 2002 and 2001, the pass-through amounts have been subject to significant adjustments.

On February 26, 2004, the CPUC approved revised electricity rates reflected in the rate design settlement to implement an overall electricity rate reduction of approximately $799 million. Although actual rates will not be reflected in customers bills until March 1, 2004, or shortly thereafter, the rate reduction is retroactive to January 2004. Because the DWR s revenue requirements will be included as a component of our total rates in 2004, any difference between the actual DWR revenue requirements and those assumed in the rate design settlement will result in an adjustment of our electricity rates. Any adjustments that occur are not expected to impact our future results of operations or financial position.

The DWR s revenue requirements are subject to various adjustments, including the reallocation of DWR contracts among the California investor-owned electric utilities, adjustments to actual deliveries and changes in allocation methodologies. In January 2004, the CPUC issued a decision finding that we over-remitted approximately $101 million in power charges to the DWR related to the DWR s 2001-2002 revenue requirement and ordered that our allocation of the DWR s 2004 revenue requirement to the customers of the California investor-owned electric utilities be reduced by this amount.

Regulatory Assets and Liabilities

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

If it is determined that a regulatory asset is no longer probable of recovery in rates, then SFAS No. 71 requires that it be written off at that time. At December 31, 2003, we reported regulatory assets (including current regulatory balancing accounts receivable) of approximately $2.2 billion and regulatory liabilities (including current balancing accounts payable) of approximately $4.2 billion.

We expect to recognize the regulatory assets created by the settlement agreement when they meet the probability requirements of SFAS No. 71. Implementation of our plan of reorganization is subject to various conditions, including the consummation of the public offering of senior bonds, the receipt of investment grade credit ratings and final CPUC approval of the settlement agreement. Under the terms of our plan of reorganization, we and Corp may determine that the CPUC order approving the settlement agreement is final even if appeals are pending. There can be no assurance that the settlement agreement will not be modified on rehearing or appeal or that our plan of reorganization will become effective. Until certain conditions or events regarding the effectiveness of our plan of reorganization discussed above are resolved further, we cannot conclude that the probability requirements of SFAS No. 71 have been met and therefore cannot record the regulatory assets contemplated in the settlement agreement.

Unbilled 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 an estimate of the electricity and natural gas load delivered with recent historical usage and rate patterns.

Surcharge Revenues

In January 2001, the CPUC authorized increases in electricity rates of $0.01 per kWh, in March 2001 of another $0.03 per kWh and in May 2001 of an additional $0.005 per kWh. The use of these surcharge revenues was initially 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 the surcharges to be used to restore our financial health by permitting us to record amounts related to the surcharge revenues as an offset to unrecovered transition costs. From January 2001 to December 31, 2003, we recognized total surcharge revenues of approximately $8.1 billion, pre-tax. The rate design settlement included a refund of approximately $125 million of surcharge revenues. We recorded a regulatory liability for the potential refund of approximately $125 million of surcharge revenues collected during 2003, which is reflected on our balance sheet at December 31, 2003. If the CPUC requires us to refund any amounts in excess of $125 million, our earnings could be materially adversely affected.

Environmental Remediation Liabilities

Given the complexities of the legal and regulatory environment regarding environmental laws, the process of estimating environmental remediation liabilities is a subjective one. We record a liability associated with environmental remediation activities when it is determined that remediation is probable and our cost can be estimated in a reasonable manner. The liability can be based on many factors, including site investigations, remediation, operations, maintenance, monitoring and closure. This liability is recorded at the lower range of estimated costs, unless a more objective estimate can be achieved. The recorded liability is re-examined every quarter.

At December 31, 2003, our accrual for undiscounted environmental liability was approximately $314 million, which was approximately $17 million lower than at December 31, 2002, mainly due to a reassessment of the estimated cost of remediation and remediation payments. Our undiscounted future costs could increase to as much as $422 million if other potentially responsible parties are not able to contribute to the settlement of these costs or the extent of contamination or necessary remediation is greater than anticipated.

Derivatives

In 2001, we adopted SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, or SFAS No. 133, which required all derivative instruments to be recognized in the financial statements at their fair value.

We have long-term purchase contracts, including power purchase and renewable energy, natural gas supply and transportation, and nuclear fuel as reflected in Capital Expenditures and Commitments discussed above. We have determined most of these contracts, including substantially all of our qualifying facility and nuclear fuel contracts, are not derivative instruments. Most of the remaining contracts that are derivative instruments are exempt from the mark-to-market requirements of SFAS No. 133 under the normal purchases and sales exception and are not reflected on the balance sheet at fair value. In addition, we hold derivative instruments that are used to offset natural gas commodity price risk and interest rate risk. These instruments qualify for cash flow hedge treatment under SFAS No. 133 and are presented on the balance sheet at fair value, which amounted to approximately $21 million at December 31, 2003.

Pension and Other Postretirement Plans

We provide qualified and non-qualified non-contributory defined benefit pension plans to our employees and retirees and certain of our affiliates employees and retirees. Our retired employees and certain of our affiliates retired employees and their eligible dependents also participate in contributory medical plans, and certain retired employees participate in life insurance plans (referred to collectively as other benefits). Amounts that we recognize as obligations to provide pension benefits under SFAS No. 87, Employers Accounting for Pensions, and other benefits under SFAS No. 106, Employers Accounting for Postretirement Benefits other than Pensions, are based on certain actuarial assumptions. Actuarial assumptions used in determining pension obligations include the discount rate, the average rate of future compensation increases and the expected return on plan assets. Actuarial assumptions used in determining other benefit obligations include the discount rate, the average rate of future compensation increases, the expected return on plan assets and the assumed health care cost trend rate. While we believe the assumptions used are appropriate, significant differences in actual experience, plan changes or significant changes in assumptions may materially affect the recorded pension and other benefit obligations and future plan expenses.

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

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed income projected returns were based on historical returns for the broad U.S. bond market. Equity returns were based primarily on historical returns of the S&P 500 Index. For our Retirement Plan, the assumed return of 8.1% compares to a ten-year actual return of 8.5%.

The rate used to discount pension and other post-retirement benefit plan liabilities was based on a yield curve developed from the Moody s AA Corporate Bond Index at December 31, 2003. This yield curve has discount rates that vary based on the maturity of the obligations. The estimated future cash flows for the pension and other post retirement obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate. For our Retirement Plan, a decrease in the discount rate from 6.25% to 6.00% would increase the accumulated benefit obligation by approximately $202 million.

Accounting Pronouncements Issued but not Yet Adopted

Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003

In January 2004, the Financial Accounting Standards Board, or FASB, issued FASB Staff Position SFAS No. 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003, or SFAS No. 106-1. SFAS No. 106-1 permits a sponsor to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003, or the Prescription Drug Act. The Prescription Drug Act, signed into law in December 2003, establishes a prescription drug benefit under Medicare (Medicare Part D) and a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. SFAS No. 106-1 does not provide specific guidance as to whether a sponsor should recognize the effects of the Prescription Drug Act in its financial statements. The Prescription Drug Act introduces two new features to Medicare that must be considered when measuring accumulated postretirement benefit costs. The new features include a subsidy to the plan sponsors that is based on 28% of an individual beneficiary s annual prescription drug costs between $250 and $5,000 and an opportunity for a retiree to obtain a prescription drug benefit under Medicare. The Prescription Drug Act is expected to reduce our net postretirement benefit costs.

We have elected to defer adoption of SFAS No. 106-1 due to the lack of specific guidance. Therefore, the net postretirement benefit costs disclosed in our consolidated financial statements do not reflect the impacts of the Prescription Drug Act on the plans. The deferral will continue to apply until specific authoritative accounting guidance for the federal subsidy is issued. Authoritative guidance on the accounting for the federal subsidy is pending and, when issued, could require information previously reported in our consolidated financial statements to change. We are currently investigating the impacts of SFAS 106-1 s initial recognition, measurement and disclosure provisions on our consolidated financial statements.

Change in Accounting for Certain Derivative Contracts

In November 2003, the FASB approved an amendment to an interpretation issued by the Derivatives Implementation Group C15, (as previously amended in October 2001 and December 2001, or DIG C15), that changed the definition of normal purchases and sales for certain power contracts that contain optionality.

The implementation guidance in DIG C15 impacts certain derivative instruments entered into after June 30, 2003. Prior to this amendment to DIG C15, most of our derivative instruments have qualified for the normal purchases and sales exception. However, it is possible that new derivative instruments and certain of our derivative instruments entered into prior to July 1, 2003 will no longer qualify for normal purchases and sales treatment under the new guidelines of DIG C15. Application of the new guidance to existing derivative instruments that were eligible for the normal purchases and sales exception under the previous DIG C15 guidance will be effective in the first quarter of 2004 as a cumulative effect of a change in accounting principle. We are currently evaluating the impacts, if any, of DIG C15 on our consolidated financial statements.

Consolidation of Variable Interest Entities

In December 2003, the FASB issued Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities, or FIN 46R, replacing Interpretation No. 46, Consolidation of Variable Interest Entities, or FIN 46, which was issued in January 2003. FIN 46R was issued to replace FIN 46 and to clarify the required accounting for interests in variable interest entities. A variable interest entity is an entity that does not have sufficient equity investment at risk, or the holders of the equity instruments lack the essential characteristics of a controlling financial interest. A variable interest entity is 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 is entitled to receive a majority of the entity s residual returns, or both.

We must apply the provisions of FIN 46R as of January 1, 2004. We are continuing to evaluate the impacts of FIN 46R s initial recognition, measurement and disclosure provisions on our consolidated financial statements and are unable to estimate the impact, if any, which will result when FIN 46R becomes effective. We have investments in unconsolidated affiliates, which are mainly engaged in the purchase of low-income residential real estate property. It is reasonably possible that we will be required to consolidate our interests in these entities as a result of the adoption of FIN 46R. At December 31, 2003, our recorded investment in these entities was approximately $21 million. As a limited partner, our exposure to potential loss is limited to our investment in each partnership.

Additional Security Measures

The NRC issued orders in 2003 regarding additional security measures for all nuclear plants, including our Diablo Canyon power plant. These orders require additional capital investment and increased operating costs. However, we do not believe these costs will have a material impact on our consolidated financial position or results of operations.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Risk Management Activities

We are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. We face market risk associated with our operations, financing arrangements, the marketplace for electricity, natural gas, electricity transmission, natural gas transportation and storage, other goods and services, and with other aspects of our business. We categorize market risks as price risk, interest rate risk and credit risk. We actively manage market risks through risk management programs that are designed to support business objectives, reduce costs, discourage unauthorized risk, reduce earnings volatility and manage cash flows. Our risk management activities often include the use of energy and financial derivative instruments, including forward contracts, futures, swaps, options, and other instruments and agreements.

We use derivative instruments only for non-trading purposes (*i.e.*, risk mitigation) and not for speculative purposes. We use derivative instruments to mitigate the risks associated with ownership of assets, liabilities, committed transactions or probable forecasted transactions. We enter into derivative instruments in accordance with approved risk management policies adopted by a risk oversight committee composed of senior officers and only after the risk oversight committee approves appropriate risk limits for each derivative instrument. The organizational unit proposing the activity must successfully demonstrate that the derivative instrument satisfies a business need and that the attendant risks will be adequately measured, monitored and controlled.

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

Price Risk

Electricity

We rely on electricity from a diverse mix of resources, including third-party contracts, amounts allocated under DWR contracts and our own electricity generation facilities. On January 1, 2003, we resumed responsibility for purchasing electricity to meet our residual net open position. We have purchased electricity on the spot market and the short-term forward market (contracts with delivery times ranging from one hour ahead to one year ahead) since that date.

It is estimated that the residual net open position will increase over time for a number of reasons, including:

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

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 electricity purchase contracts or the DWR allocated contracts, would immediately increase our residual net open position. We expect to satisfy at least some of our residual net open position through new contracts.

The settlement agreement contemplates that we will recover our reasonable costs of providing utility service, including power procurement costs. In addition, California law requires that through 2006 the CPUC review revenues and expenses associated with a CPUC-approved procurement plan at least semi-annually and adjust retail electricity rates, or order refunds when there is an undercollection or overcollection exceeding 5% of our prior year electricity procurement revenues, excluding the revenue collected on behalf of the DWR. In addition, the CPUC has established maximum annual procurement disallowance for our administration of the DWR allocated contracts and least-cost dispatch of $36 million. Adverse market price changes are not expected to impact our net income, while these cost recovery regulatory mechanisms remain in place. However, we are at risk

to the extent that the CPUC may in the future disallow transactions that do not comply with the CPUC-approved short-term procurement plan. Additionally, adverse market price changes could impact the timing of our cash flows.

Nuclear Fuel

We purchase nuclear fuel for our Diablo Canyon power plant through contracts with terms ranging from two to five years. These agreements are with large, well-established international producers for our long-term nuclear fuel agreements in order to diversify our commitments and ensure security of supply.

Nuclear fuel purchases are subject to tariffs of up to 50% on imports from certain countries. Our nuclear fuel costs have not increased based on the imposed tariffs because the terms of our existing long-term contracts do not include these costs. However, once these contracts begin to expire in 2004, the costs under new nuclear fuel contracts may increase. While the cost recovery regulatory mechanisms under California law described above remain in place, adverse market changes in nuclear fuel prices are not expected to materially impact net income.

Natural Gas

We enter into physical and financial natural gas commodity contracts of up to one-and-a-half years in length to fulfill the needs of our retail core customers. Changes in temperature cause natural gas demand to vary daily, monthly and seasonally. Consequently, significant volumes of gas must be purchased in the spot market. To mitigate the risk of price volatility, we enter into various financial instruments, including options that may extend for up to five months in length. Our cost of natural gas includes the cost of Canadian and interstate transportation of natural gas purchased for our core customers.

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 99% to 102% of the benchmark, are considered reasonable and are fully recovered in customers rates. One-half of the costs above 102% of the benchmark are recoverable in customers rates, and our customers receive three-fourths of any savings resulting from our cost of natural gas that is less than 99% of the benchmark in their rates. While this cost recovery mechanism remains in place, changes in the price of natural gas are not expected to materially impact net income.

Transportation and Storage

We currently face price risk for the portion of intrastate natural gas transportation capacity that is not used by core customers. Noncore customers contract with us for natural gas transportation and storage, along with natural gas parking and lending services. We are at risk for any natural gas transportation and storage revenue volatility. Transportation is sold at competitive market-based rates within a cost-of-service tariff framework. There are significant seasonal and annual variations in the demand for natural gas transportation and storage services. We sell most of our pipeline capacity based on the volume of natural gas that is transported by our customers. As a result, our natural gas transportation revenues fluctuate.

We use a value-at-risk methodology to measure the expected maximum daily change in the 18-month forward value of our transportation and storage portfolio. The value-at-risk provides an indication of our exposure to potential high-risk market conditions, and market opportunities for improved revenues based on price changes, high-price volatility or correlation between pricing locations. It is also an important indicator of the effectiveness of hedge strategies on a portfolio. The value-at-risk methodology is based on a 95% confidence level, which means that there is a 5% probability that the portfolio will incur a loss in value in one day at least as large as the reported value-at-risk. The one-day liquidation period assumption of the value-at-risk methodology does not match the longer-term holding period of our transportation and storage contract portfolio.

Our value-at-risk for our transportation and storage portfolio was approximately $4.2 million at December 31, 2003 and approximately $4 million at December 31, 2002. Our high, low and average transportation and storage value-at-risk during 2003 was approximately $12.8, $1.7 and $5.4 million, respectively.

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, volumetric risk, 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.

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.

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2003, if interest rates changed by 1% for all current variable rate debt held by us, the change would affect net income by an immaterial amount, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

As discussed above, we plan to issue a significant portion of the senior bonds and establish credit and accounts receivable facilities to facilitate payment of allowed claims in our Chapter 11 proceeding. We entered into derivative instruments, which expire in June 2004, to partially hedge the interest rate risk on up to $7.4 billion of the long-term debt to be issued.

The hedges are reflected on our balance sheet at fair value in other current assets. The cost of the hedges, purchased at fair value, was approximately $45 million. The fair value of the hedges at December 31, 2003 was approximately $17 million. At December 31, 2003, a hypothetical 1% decrease in interest rates would cause the fair value of the interest rate hedges to fall below $1 million; however, the change in fair value of the interest rate hedges would primarily be reported in regulatory accounts, and would be offset by changes in interest expense once the forecasted debt is issued.

Credit Risk

Credit risk is the risk of loss that we would incur if customers or counterparties failed to perform their contractual obligations.

We had gross accounts receivable of approximately $2.5 billion at December 31, 2003 and approximately $2.0 billion at December 31, 2002. The majority of the accounts receivable are associated with our residential and small commercial customers. Based upon historical experience and evaluation of then-current factors, allowances for doubtful accounts of approximately $68 million at December 31, 2003 and approximately $59 million at December 31, 2002 were recorded against those accounts receivable. In accordance with tariffs, credit risk exposure is limited by requiring deposits from new customers and from those customers whose past payment practices are below standard. We have a regional concentration of credit risk associated with our receivables from residential and small commercial customers in northern and central California. However, material loss due to non-performance from these customers is not considered likely.

We manage credit risk for our largest customers and counterparties by assigning credit limits based on an evaluation of their financial condition, net worth, credit rating and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored frequently and a detailed credit analysis is performed at least annually.

Credit exposure for our largest customers and counterparties is calculated daily. If exposure exceeds the 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 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.

We calculate gross credit exposure for each of our largest customers and counterparties as the current mark-to-market value of the contract (*i.e.*, the amount that would be lost if the counterparty defaulted today) plus or minus any outstanding net receivables or payables, before the application of credit collateral. During 2003, we recognized no material losses due to contract defaults or bankruptcies. At December 31, 2003, there were three counterparties that represented greater than 10% of our net credit exposure. We had two investment grade counterparties that represented a total of approximately 32% of our net credit exposure and one below-investment grade counterparty that represented approximately 12% of our net credit exposure.

We conduct business with customers or vendors mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. This concentration of counterparties may impact our overall exposure to credit risk because counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions.

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.

In September 2001, we and Corp proposed a plan of reorganization that would have disaggregated our businesses. In April 2002, the CPUC, later joined by the Official Committee of Unsecured Creditors, proposed an alternate plan of reorganization that would not have disaggregated our businesses. 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. On June 19, 2003, we, Corp and the staff of the CPUC announced the principal terms of the settlement agreement.

The CPUC Settlement Agreement

On December 19, 2003, we, Corp and the CPUC entered into the settlement agreement that contemplates a new plan of reorganization to supersede the competing plans.

In the settlement agreement, we and Corp agreed that we would remain a vertically integrated utility primarily under CPUC regulation. The 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 S&P), and pay in full all our valid creditor claims, plus applicable interest.

The settlement agreement contains a statement of intent that it is in the public interest to restore us to financial health and to maintain and improve our financial health 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 settlement agreement includes a statement of intent that it is fair and in the public interest to allow us to recover, over a reasonable time, our prior uncollected costs and to provide the opportunity for our shareholders to earn a reasonable rate of return on our business. Under the settlement agreement, we will release claims against the CPUC that we or Corp would have retained under the plan of reorganization we proposed in September 2001.

On January 20, 2004, several parties filed applications with the CPUC requesting that the CPUC rehear and reconsider its decision approving the settlement agreement on the basis that the settlement agreement does not comply with California law. Although the CPUC is not required to act on these applications within a specific time period, if the CPUC has not acted on an application within 60 days, that application may be deemed denied for purposes of seeking judicial review. No additional party may request rehearings or make appeals of the CPUC s approval of the settlement agreement. We cannot predict the timing or outcome of the requests for rehearing or any appeals.

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. 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 we receive from energy suppliers relating to specified procurement costs incurred during the California energy crisis, including from the El Paso settlement related to electricity refunds, but not natural gas refunds, will reduce the outstanding balance of the $2.21 billion after-tax regulatory asset and the related amortization. On February 26, 2004, the CPUC approved the rate design settlement which set a revenue requirement reflecting a reduction of this regulatory asset by approximately $179 million for certain of these matters.

The unamortized balance of the $2.21 billion after-tax regulatory asset will earn a rate of return on its equity component of no less than 11.22% annually for its nine-year 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. The rate of return on the $2.21 billion after-tax regulatory asset would be eliminated if we complete the refinancing discussed below. Instead, we would collect from customers amounts sufficient to service the securitized debt.

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 Senate Bill 1976, or 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 settlement agreement provides that the CPUC will not discriminate against us because of our Chapter 11 proceeding, 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 settlement agreement, the $2.21 billion after-tax regulatory asset or any other matters addressed in or resolved by the settlement agreement.

The CPUC agreed in the settlement agreement to maintain our retail electricity rates at their pre-existing levels through the end of 2003. Effective January 1, 2004, the CPUC may adjust our retail electricity rates prospectively consistent with the settlement agreement, our plan of reorganization, the confirmation order and California law. The settlement agreement includes a statement of intent that under the settlement agreement and our plan of reorganization, retail electricity rates will be reduced effective January 1, 2004 with further 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 S&P 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 CPUC also agreed to act promptly on certain of our pending ratemaking proceedings, including our pending 2003 general rate case. The outcome of these proceedings may result in the establishment of additional regulatory assets on our consolidated balance sheet.

California Department of Water Resources Contracts

The settlement agreement provides that the CPUC will not require us to accept an assignment of, or assume legal or financial responsibility for, the DWR power purchase contracts, unless each of the following conditions has been met:

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

the CPUC first makes a finding that, for purposes of assignment or assumption, the DWR power purchase contracts to be 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 power purchase contracts to be assumed over their lives without further review.

Under the settlement agreement, the CPUC retains and, after any assumption of the DWR contracts, will retain the right to review the prudence of our administration and dispatch of the DWR contracts consistent with applicable law.

Headroom

The CPUC agreed and acknowledged that the headroom, surcharge and base 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 proceeding, have been included in our retail electricity rates consistent with state and federal law and are not subject to refund. The settlement agreement defines headroom as our total net after-tax income reported under GAAP, less earnings from operations (a non-GAAP financial measure that has been historically reported by Corp in its earnings press release), plus after-tax amounts accrued for Chapter 11-related administration and Chapter 11-related interest costs, all multiplied by 1.67, provided that the calculation reflects the outcome of our 2003 general rate case. The settlement agreement provides that if headroom revenue accrued by us during 2003 is greater than $875 million, pre-tax, we will refund the excess to ratepayers.

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 or the date on which CPUC approval of the 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. Michael Peevey, et al. (addressing the federal filed rate doctrine), withdraw the original plan of reorganization and dismiss certain 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 filed.

On or as soon as practicable after the later of the effective date of our plan of reorganization or the date on which CPUC approval of the 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 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 September 2001 Plan of Reorganization

As required by the 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 plan of reorganization we proposed in September 2001. We have also suspended all actions to obtain or transfer licenses, permits and franchises to implement the proposed 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 life of the regulatory asset neither we nor Corp, nor our respective affiliates or subsidiaries, 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 $100 million in cash over ten years, although we will be entitled to recover these payments in rates; and

- we will establish a California non-profit corporation funded with $30 million in cash payable by us over five years, with no recovery of these payments in rates, 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 44,000 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 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 settlement agreement, our plan of reorganization or the confirmation order. The 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 settlement agreement, our plan of reorganization or the confirmation order.

Term and Enforceability

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

Fees and Expenses

The settlement agreement requires us to reimburse the CPUC for its professional fees and expenses incurred in connection with the Chapter 11 proceeding. These amounts will be recovered from customers over a reasonable time of up to four years. This accrual will be recorded when the applicable GAAP requirements are met. Corp s professional fees and expenses incurred in connection with the Chapter 11 proceeding will not be reimbursed by us or from our customers.

Refinancing Supported by a Dedicated Rate Component

In connection with the settlement agreement, we and Corp agreed to seek to refinance the remaining unamortized pre-tax balance of the $2.21 billion after-tax regulatory asset and associated federal, state and franchise taxes, up to a total of $3.0 billion, as expeditiously as practicable after the effective date of our plan of reorganization using a securitized financing supported by a dedicated rate component, provided the following conditions are met:

- authorizing California legislation satisfactory to the CPUC, TURN and us is passed and signed into law allowing securitization of the regulatory asset and associated federal and state income and franchise taxes and providing for the collection in our rates of any portion of the associated tax amounts not securitized;

- the CPUC determines that, on a net present value basis, the refinancing would save customers money over the term of the securitized debt compared to the regulatory asset;

- the refinancing will not adversely affect our issuer or debt credit ratings; and

- we obtain, or decide we do not need, a private letter ruling from the Internal Revenue Service, or IRS, confirming that neither the refinancing nor the issuance of the securitized debt is a presently taxable event.

We would be permitted to complete the refinancing in up to two tranches up to one year apart. The first tranche would be no less than the fully unamortized, after-tax balance of the regulatory asset. The second tranche would cover the associated federal and state income taxes and franchise taxes. However, we would not be required to securitize more than $3.0 billion in total in both tranches and, to the extent this would require callable debt or debt with earlier maturities than we would otherwise issue as part of the implementation of our plan of reorganization, these costs generally would be recoverable in rates. Upon refinancing, the rate of return on this regulatory asset would be eliminated. Instead, we would collect from customers amounts sufficient to service the securitized debt. We would use the securitization proceeds to rebalance our capital structure in order to maintain the capital structure provided in the settlement agreement.

Terms of Our Plan of Reorganization

The terms of the settlement agreement are reflected in our plan of reorganization, and the full settlement agreement is incorporated by reference into our plan of reorganization as a material and integral part of the plan. Our plan of reorganization was confirmed by the bankruptcy court on December 22, 2003. 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. We will make these payments from the proceeds from the offering of a significant portion of the senior bonds, cash on hand and draws on credit and accounts receivable facilities. 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 proceeding 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 two CPUC commissioners who did not vote to approve the settlement agreement and a municipality have filed appeals of the bankruptcy court s confirmation order in the district court citing similar objections to those included in their requests for rehearing and reconsideration of the CPUC s decision approving the settlement agreement. On January 5, 2004, the bankruptcy court denied a request to stay the implementation of our plan of reorganization until the appeals are resolved. The district court will set a schedule for briefing and argument of the appeals at a later date. No additional parties may request rehearings or make appeals of the bankruptcy court s confirmation order. We cannot predict the timing or outcome of the requests for rehearing and appeals.

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 senior bonds provided for under our plan of reorganization;

Moody s has issued an issuer rating for us of not less than Baa3 and S&P has issued long-term issuer credit ratings for us of not less than BBB-;

Moody s and S&P have issued credit ratings for the senior bonds provided for under our plan of reorganization of not less than Baa3 and BBB-, respectively;

the CPUC has given final approval of the settlement agreement;

we, Corp and the CPUC have executed and delivered the settlement agreement;

the CPUC has given final approval of all of the financings, securities and accounts receivable programs provided for in our plan of reorganization; and

the CPUC has given final approval of 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 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 senior bonds) while the CPUC s approvals are subject to pending appeals or further rights of appeal. In addition, our plan of reorganization provides that we may waive any or all of the conditions described under the first five bullets listed above with the consent of the Official Committee of Unsecured Creditors.

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, electricity 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, 2003, we served approximately 4.9 million electricity distribution customers and approximately 3.9 million natural gas distribution customers in a service territory covering over 70,000 square miles. In 2003, we delivered approximately 80,156 GWh of electricity, which included approximately 8,978 GWh transmitted to direct access customers, and delivered approximately 804 Bcf of natural gas, which included approximately 525 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, 2003, our electricity generation portfolio consisted of approximately 6,420 MW of owned generating capacity and approximately 5,450 MW of generating capacity under contract, for a combined generating capacity of approximately 11,870 MW. We are the largest non-governmental producer of hydroelectric power in the United States.

We own and operate an electricity transmission system that comprises most of the high-voltage electricity transmission lines and facilities in northern and central California. Our high-voltage transmission system consists of approximately 18,612 circuit miles of interconnected electricity 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 6,350 miles of transportation 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 December 31, 2003, our total assets were approximately $29.1 billion, of which approximately $18.1 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 electricity and/or natural gas to approximately one out of every 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, electricity 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 46 of California s 58 counties, comprising most of northern and central California. Our network consists of approximately 120,000 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead). Our network includes 89 transmission substations and 45 transmission switching stations, 609 distribution substations and 117 low voltage distribution substations, and 264 combined transmission and distribution substations. A transmission substation is a facility where voltage is transformed from one transmission voltage level to another. Combined transmission and distribution substations have both transmission and distribution transformers.

Our distribution network interconnects to our electricity transmission system at 1,012 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 electricity transmission system transmits electricity, ranging from 500 kV to 60 kV, to lower voltages, ranging from 44 kV to 2.4 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 2003 electricity deliveries represented by each of our major customer classes:

2003 ELECTRICITY DELIVERIES

(80,156 GWhs)

Electricity Distribution Operating Statistics

The following table shows certain of our operating statistics from 1999 to 2003 for electricity sold or delivered, including the classification of sales and revenues by type of service.

	2003	2002	2001	2000	1999
Customers (average for the year):					
Residential	4,286,085	4,171,365	4,165,073	4,071,794	4,017,428
Commercial	493,638	483,946	484,430	471,080	474,710
Industrial	1,372	1,249	1,368	1,300	1,151
Agricultural	81,378	78,738	81,375	78,439	85,131
Public street and highway lighting	26,650	24,119	23,913	23,339	20,806
Other electric utilities	4	5	5	8	12
Total	4,889,127	4,759,422	4,756,164	4,645,960	4,599,238
Deliveries (in GWh):(1)					
Residential	29,024	27,435	26,840	28,753	27,739
Commercial	31,889	31,328	30,780	31,761	30,426
Industrial	14,653	14,729	16,001	16,899	16,722
Agricultural	3,909	4,000	4,093	3,818	3,739
Public street and highway lighting	605	674	418	426	437
Other electric utilities	76	64	241	266	167
Subtotal	80,156	78,230	78,373	81,923	79,230
DWR	(23,342)	(21,031)	(28,640)		
Total non-DWR electricity	56,814	57,199	49,733	81,923	79,230
Revenues (in millions):					
Residential	$ 3,671	$ 3,646	$ 3,396	$ 3,062	$ 2,975
Commercial	4,440	4,588	4,105	3,110	2,980
Industrial	1,410	1,449	1,554	1,053	1,044
Agricultural	522	520	525	420	404
Public street and highway lighting	69	73	60	43	49
Other electric utilities	24	10	39	26	17
Subtotal	10,136	10,286	9,679	7,714	7,469
DWR	(2,243)	(2,056)	(2,173)		
Direct access credits	(277)	(285)	(461)	(1,055)	(348)
Miscellaneous(2)	(52)	193	244	202	162
Regulatory balancing accounts	18	40	37	(7)	(51)
Total electricity operating revenues	$ 7,582	$ 8,178	$ 7,326	$ 6,854	$ 7,232
Other Data:					
Average annual residential usage (kWh)	6,772	6,577	6,444	7,062	6,905

Average billed revenues (cents per kWh):					
Residential	12.65	13.29	12.65	10.65	10.72
Commercial	13.92	14.65	13.34	9.79	9.79
Industrial	9.62	9.84	9.71	6.23	6.24
Agricultural	13.35	13.00	12.83	11.00	10.81
Net plant investment per customer	$ 2,689	$ 2,105	$ 2,018	$ 1,969	$ 2,388

(1) These amounts include electricity provided to direct access customers who procure their own supplies of electricity. Direct access deliveries amounted to 8,978 GWh in 2003, 7,433 GWh in 2002, 3,982 GWh in 2001, 9,662 GWh in 2000 and 9,022 GWh in 1999.

(2) Miscellaneous revenues in 2003 include a $125 million reduction due to refunds to electricity customers from generation-related revenues in excess of generation-related costs.

Electricity Resources

The following chart shows the percentage of our total sources of electricity for 2003 represented by each major electricity resource:

2003 ELECTRICITY RESOURCES

We are required to dispatch all of the electricity resources within our portfolio, including electricity provided under DWR contracts, in the most cost-effective way. To the extent our electricity resources are not sufficient to meet the demand of our customers, we purchase electricity from the wholesale electricity market. At other times, least-cost dispatch requires us to schedule more electricity than is necessary to meet our retail load and to sell this additional electricity on the wholesale electricity market. We typically schedule this excess electricity when the expected electricity sales proceeds exceed the variable costs to operate a generation facility or buy electricity on an optional contract.

Generation Facilities

At December 31, 2003, 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)
Nuclear:			
Diablo Canyon	San Luis Obispo	2	2,174
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(1)	Humboldt	2	105
Hunters Point(2)	San Francisco	2	215
Mobile turbines	Humboldt	2	30
Fossil fuel subtotal		6	350
Total		118	6,420

(1) The Humboldt Bay facilities consist of a retired nuclear generation unit, or Humboldt Bay Unit 3, and two operating fossil fuel-fired plants.

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

Diablo Canyon Power Plant. Our Diablo Canyon power plant consists of two nuclear power reactor units, each capable of generating up to approximately 1,087 MW of electricity. 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, 2003, our Diablo Canyon power plant achieved a capacity factor of approximately 88.5%.

The following table outlines the Diablo Canyon power plant s refueling schedule for the next five years. The Diablo Canyon power plant refueling outages are typically scheduled every 19 to 21 months. The average length of a refueling outage over the last five years has been approximately 35 days. It is anticipated, however, that additional work will be required during future scheduled outages leading up to the steam generator replacements in 2008 and 2009 discussed below. This additional work will lengthen the forecasted outage durations to the time periods shown below. The table below shows outages of up to 80 days to accommodate non-routine tasks, such as expanded steam generator inspection and repair, low pressure turbine rotor replacement and the first of two proposed steam generator replacements. The actual refueling schedule and outage duration will depend on the scope of the work required for a particular outage and other factors.

	2004	2005	2006	2007	2008
Unit 1					
Refueling	March	October		April	
Duration (days)	48	45		35	
Startup	May	November		June	
Unit 2					
Refueling	October		April		February
Duration (days)	42		42		80
Startup	December		May		April

During a routine inspection conducted as part of the last refueling of Unit 2 in February 2003, we found indications of steam generator tube cracking in locations and of a size not previously expected. After careful inspection and analysis, Unit 2 was able to safely restart after that outage and we received the approval of the NRC to operate without further steam generator inspection until the next scheduled refueling in the fall of 2004. We are, however, planning to accelerate the replacement of the steam generators in Unit 2 from 2009 to 2008. We plan to replace Unit 1 s steam generators in 2009. The capital expenditures necessary to complete these projects are discussed further in Management s Discussion and Analysis of Financial Condition and Results of Operations.

Nuclear Fuel Agreements

We have purchase agreements for nuclear fuel. These agreements have terms ranging from two to five years and are intended to ensure long-term fuel supply. These agreements are with a number of large, well-established international producers of nuclear fuel in order to diversify our commitments and provide security of supply. Pricing terms are also diversified, ranging from fixed prices to base prices that are adjusted using published information. Deliveries provided under nine of the eleven contracts in place at the end of 2003 will end by 2005. In most cases, our nuclear fuel agreements are requirements-based. Payments for nuclear fuel amounted to approximately $57 million in 2003, $70 million in 2002 and $50 million in 2001.

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 water rights as specified in 83 permits and licenses and 163 statements of water diversion and use. With the exception of three non-jurisdictional powerhouses, all of our powerhouses are licensed by the FERC. Pursuant to the Federal Power Act, the term of a hydroelectric project license issued by the FERC is between 30 and 50 years. In the last three years, we have received six renewed hydroelectric project licenses from the FERC. We currently have seven hydroelectric projects undergoing FERC relicensing. We will begin relicensing proceedings on two additional hydroelectric projects within the next two years. Licenses associated with 928 MW expire within the next five years. Licenses associated with approximately 2,959 MW expire between 2009 and 2043.

DWR Power Purchases

In January 2001, because of the deteriorating credit conditions of the California investor-owned electric utilities, the State of California authorized the DWR to purchase electricity to meet the utilities net open positions. California 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. We and the other California investor-owned electric utilities act as the billing and collection agent for the DWR s sales of electricity to retail customers.

On September 19, 2002, the CPUC issued a decision allocating electricity from 19 of the DWR s contracts to our customers. Electricity from DWR allocated contracts represented approximately 29% of our total sources of electricity in 2003. In January 2003, we became responsible for scheduling and dispatching the electricity subject to the DWR allocated contracts on a least-cost basis and for many administrative functions associated with those contracts. During 2004, a total average capacity of approximately 2,700 MW of the electricity under the DWR allocated contracts is subject to must take provisions that require the DWR to take and pay for the electricity regardless of whether the electricity is needed. A total average capacity for 2004 of approximately 1,200 MW of the electricity under DWR allocated contracts is subject to provisions that require the DWR to pay a capacity charge, but do not require the purchase of electricity unless that electricity is dispatched and 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 power purchase contracts to the California investor-owned electric utilities as soon as possible. However, the DWR power purchase contracts cannot be transferred to us without the consent of the CPUC. The 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 power purchase 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 S&P will be no less than A;

the CPUC first makes a finding that, for purposes of assignment or assumption, the DWR power purchase contracts to be 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 power purchase contracts to be assumed without further review.

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

Third Party Agreements

Qualifying Facilities. We are required by CPUC decisions to purchase energy and capacity from independent power producers that are qualifying facilities under the Public Utility Regulatory Policies Act of 1978, or PURPA. Under PURPA, the CPUC required California investor-owned electric utilities to enter into a series of long-term power purchase agreements with qualifying facilities 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 CPUC-approved energy prices, while capacity payments are based on the qualifying facility s total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the facility fails to meet or exceeds performance requirements specified in the applicable power purchase agreement.

At December 31, 2003, we had qualifying facility power purchase agreements with approximately 300 qualifying facilities for approximately 4,400 MW in operation. Agreements for approximately 4,000 MW expire between 2004 and 2028. Qualifying facility power purchase agreements for approximately 400 MW have no specific expiration dates and will terminate only when the owner of the qualifying facility exercises its termination option. We also have agreements with 50 qualifying facilities that are not currently providing or expected to provide electricity. The total of approximately 4,400 MW consists of approximately 2,600 MW from cogeneration projects, 800 MW from wind projects and 1,000 MW from other projects, including biomass, waste-to-energy, geothermal, solar and hydroelectric. On January 22, 2004, the CPUC adopted a decision that requires California investor-owned electric utilities to allow owners of qualifying facilities with power purchase agreements expiring before the end of 2005 to extend these contracts for five years. Qualifying facility power purchase agreements accounted for approximately 20% of our 2003 electricity sources, approximately 25% of our 2002 electricity sources and approximately 21% of our 2001 electricity sources. No single qualifying facility power purchase agreement accounted for more than 5% of our electricity sources during any of these periods.

As a result of the energy crisis, we owed approximately $1 billion to qualifying facilities when we filed our Chapter 11 petition. Through December 31, 2003, the principal payments made to the qualifying facilities amounted to $998 million.

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, and variable payments for operating and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. Our irrigation district and water agency contracts accounted for approximately 5% of our 2003 electricity sources, approximately 4% of our 2002 electricity sources and approximately 3% of our 2001 electricity sources.

Electricity Purchases to Satisfy the Residual Net Open Position. On January 1, 2003, we resumed purchasing electricity to meet our residual net open position. During that year, more than 14,000 GWh of electricity were bought and sold in the wholesale market to manage the 2003 residual net open position. Most of our contracts entered into in 2003 had terms of less than one year. During 2004, we plan to enter into contracts of longer duration to satisfy our near-term residual net open position.

Renewable Energy Requirement. California law requires that, beginning in 2003, each California investor-owned electric utility must increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2017. We met our 2003 commitment and the CPUC has approved several contracts intended to meet our 2004 renewable energy requirement.

WAPA

In 1967, we and WAPA entered into several long-term power contracts governing the interconnection of our respective electricity transmission systems, the use of our electricity transmission and distribution systems by WAPA, and the integration of our respective customer demands and electricity 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. The contracts are scheduled to terminate on December 31, 2004. Termination is subject to FERC approval, which we expect to receive.

The costs to fulfill our obligations to WAPA cannot be accurately estimated at this time. Both the purchase price and the amount of electricity WAPA will need from us in 2004 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, WAPA s net amount purchased from us was approximately 4,804 GWh in 2003, 3,619 GWh in 2002 and 4,823 GWh in 2001.

Electricity Transmission

At December 31, 2003, we owned 18,612 circuit miles of interconnected transmission lines operated at voltages of 500 kV to 60 kV and transmission substations with a capacity of 42,798 MVA. Electricity is transmitted across these lines and substations and is then distributed to customers through 120,428 circuit miles of distribution lines and substations with a capacity of 24,218 MVA. In 2003, we delivered 80,156 GWh to our customers, including 8,978 GWh delivered to direct access customers. We are interconnected with electric power systems in the Western Electricity Coordinating Council which includes 14 western states, Alberta and British Columbia, Canada and parts of Mexico.

In connection with electricity industry restructuring, the California investor-owned electric 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. 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 electricity transmission system. We are engaged in the following significant expansion projects:

Path 15. 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. The improvements are intended to mitigate transmission constraints in this area. 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 October 2004.

Jefferson-Martin. This project entails laying 28 miles of 230 kV underground transmission facilities from Redwood City to Daly City that will provide additional transmission system reliability in San Francisco and northern San Mateo County. This project is expected to be completed in December 2005.

Nuclear Insurance

We have several types of nuclear insurance for our Diablo Canyon power plant and Humboldt Bay Unit 3. 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 nuclear incident. Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss causing a prolonged 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 purchased the maximum available public liability insurance of $300 million for the Diablo Canyon power plant. The balance of the $10.9 billion of liability protection is covered by a loss-sharing program, or secondary financial protection among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of reactors 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 the Diablo Canyon power plant has two nuclear reactors 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. Although the Price-Anderson Act expired on December 31, 2003, coverage continues to be provided to all licensees, including the Diablo Canyon power plant, that had coverage before December 31, 2003. Congress may address the renewal of the Price Anderson Act in future energy legislation.

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

Natural 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 2003, we served approximately 3.9 million natural gas distribution customers. The total volume of natural gas throughput during 2003 was approximately 804 Bcf.

At December 31, 2003, our natural gas system consisted of 39,510 miles of distribution pipelines, 6,350 miles of transportation pipelines and three storage facilities. Our distribution network connects to our transportation and storage system at approximately 2,200 major interconnection points. Our Line 400/401 interconnects with the natural gas transportation pipeline of Gas Transmission Northwest Corporation, a subsidiary of National Energy & Gas Transmission, Inc., at the California-Oregon border. This line has a receipt capacity at the border of 2.0 Bcf per day. Our Line 300, which interconnects with the U.S. southwest and California-Oregon pipeline systems owned by third parties (Transwestern Pipeline Co., or 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. Through interconnections 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 and the southwestern United States. We are also supplied by natural gas fields in California.

We also own and operate three underground natural gas storage fields located along our transportation and storage system in close proximity to approximately 90% of our end-user demand. These storage fields have a combined annual cycle capacity of approximately 42 Bcf. In addition, two independent storage operators are interconnected to our northern California transportation system.

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 2003, core customers represented over 99% of our total customers and approximately 35% of our total natural gas deliveries, while noncore customers comprised less than 1% of our total customers and approximately 65% 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. When 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, receive natural gas bundled services from us.

In March 2001 we stopped providing procurement service to noncore customers. 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 December 2003, the CPUC approved our request to prohibit electricity generation, cogeneration, enhanced oil recovery and refinery, and other large noncore customers from electing to transfer to core service. The CPUC also required smaller noncore customers to sign up for a minimum five-year term if they elect to transfer to core service. We made this request because of our concern that significant transfers of noncore customers to core service would cause large increases in our natural gas supply portfolio demand and 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.

We offer transportation, distribution and storage services as separate and distinct services to our noncore customers. These customers may elect to receive storage services from us or competitive storage providers. Noncore customers interconnected at a transportation level only pay for transportation service, while those interconnected at a distribution level pay for both transportation and distribution service. 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 available for all natural 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. Our results of operations can, however, be affected by noncore consumption levels because there are no similar regulatory balancing accounts related to noncore customers. Approximately 96% of our natural gas distribution base revenues are recovered from core customers and 4% are recovered from noncore customers.

The California Gas Report, which presents the outlook for natural gas requirements and supplies for California over a long-term planning horizon, is prepared annually by the California electric and natural gas utilities. The 2002 California Gas Report updated our annual natural gas requirements forecast for the years 2002 through 2023, forecasting average annual growth in our natural 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 number and location of electricity generation facilities.

The following chart shows the percentage of our total 2003 natural gas deliveries represented by each of our major customer classes:

2003 NATURAL GAS DELIVERIES

(804 Bcf)

Note: Deliveries to industrial and other natural gas utilities, which amounted to less than 1% of total deliveries in 2003, are not included in the chart.

Natural Gas Operating Statistics

The following table shows our operating statistics from 1999 through 2003 (excluding subsidiaries) for natural gas, including the classification of sales and revenues by type of service:

	2003	2002	2001	2000	1999
Customers (average for the year):					
Residential	3,744,011	3,738,524	3,705,141	3,642,266	3,593,355
Commercial	208,857	206,953	205,681	203,355	203,342
Industrial	1,988	1,819	1,764	1,719	1,625
Other gas utilities	6	5	6	6	4
Total	3,954,862	3,947,301	3,912,592	3,847,346	3,798,326
Gas supply (MMcf):					
Purchased from suppliers in:					
Canada	196,278	210,716	209,630	216,684	230,808
California	(7,421)(1)	19,533	20,352	32,167	18,956
Other states	102,941	67,878	76,589	75,834	107,226
Total purchased	291,798	298,127	306,571	324,685	356,990
Net (to storage) from storage	1,359	(218)	(27,027)	19,420	(980)
Total	293,157	297,909	279,544	344,105	356,010
Utility use, losses, etc. (2)	(14,307)	(16,393)	(8,988)	(62,960)	(47,152)
Net gas for sales	278,850	281,516	270,556	281,145	308,858
Bundled gas sales (MMcf):					
Residential	198,580	202,141	197,184	210,515	233,482
Commercial	79,891	78,812	72,528	66,443	70,093

	2003	2002	2001	2000	1999
Industrial	379	563	831	4,146	5,255
Other gas utilities			13	41	28
Total	278,850	281,516	270,556	281,145	308,858
Transportation only (MMcf):	525,353	508,090	646,079	606,152	484,218
Revenues (in millions):					
Bundled gas sales:					
Residential	$ 1,836	$ 1,379	$ 2,308	$ 1,681	$ 1,543
Commercial	697	499	783	513	449
Industrial	1	3	16	35	24
Miscellaneous	(30)	128	(93)	84	(47)
Regulatory balancing accounts	68	11	(253)	132	(260)
Bundled gas revenues	2,572	2,020	2,761	2,445	1,709
Transportation service only revenue	284	316	375	338	287
Operating revenues	$ 2,856	$ 2,336	$ 3,136	$ 2,783	$ 1,996
Selected Statistics:					
Average annual residential usage (Mcf)	53	54	53	59	65
Average billed bundled gas sales revenues per Mcf:					
Residential	$ 9.25	$ 6.82	$ 11.70	$ 7.98	$ 6.61
Commercial	8.73	6.33	10.80	7.72	6.40
Industrial	2.48	4.35	19.15	8.53	4.69
Average billed transportation only revenue per Mcf	0.54	0.62	0.58	0.56	0.59
Net plant investment per customer	$ 1,261	$ 1,006	$ 970	$ 1,003	$ 1,011

(1) This total includes sales of 21,632 MMcf made principally at the California border. Purchases in California totaled 14,211 MMcf.

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

Natural Gas Supplies

We purchase natural gas to serve our core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of our portfolio of natural gas purchase contracts have fluctuated, generally based on market conditions. During 2003, we purchased approximately 292,000 MMcf of natural gas (net of the sale of excess supply) from 48 suppliers. Substantially all this natural gas was purchased under contracts with a term of less than one year. Our largest individual supplier represented approximately 9.6% of the total natural gas volume we purchased during 2003.

The following table shows the total volume and the average price of natural gas in dollars per Mcf of our natural gas purchases by region during each of the last five years. The average prices for Canadian and U.S. southwest gas shown below include the commodity natural gas prices, pipeline demand or reservation charges, transportation charges and other pipeline assessments. The volumes purchased are shown net of sales of excess supplies of gas. In 2003, the sale of excess supplies to parties located in California exceeded purchases from parties located in California.

	2003		2002		2001		2000		1999	
	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price
Canada	196,278	$4.73	210,716	$2.42	209,630	$ 4.43	216,684	$4.05	230,808	$2.50
California (1)	(7,421)	$3.39	19,533	$2.88	20,352	$11.55	32,167	$8.20	18,956	$2.45
Other states (substantially all U.S. southwest)	102,941	$4.63	67,878	$3.04	76,589	$10.41	75,834	$5.99	107,226	$2.42
Total/weighted average	291,798	$4.73	298,127	$2.59	306,571	$ 6.40	324,685	$4.92	356,990	$2.47

(1) This total includes sales made principally at the California border of 21,632 MMcf. Purchases in California totaled 14,211 MMcf.

We also routinely sell contracted natural gas supplies that exceed daily core customer requirements and to comply with pipeline balancing requirements. We also may sell natural gas supplies if we can repurchase those natural gas supplies at a lower cost, thereby lowering overall costs for core natural gas customers. These sales opportunities increase during periods of price volatility. During 2003, both daily core customer requirements and natural gas prices were extremely volatile, leading to a high quantity of natural gas sales. Total natural gas sales in 2003 were approximately 7% of the total volume of natural gas supplies purchased for our core natural gas customers.

Natural Gas Gathering Facilities

Our natural gas gathering system collects and processes natural gas from third-party wells in California. The natural gas is processed to remove various impurities from the natural gas stream and to odorize the natural gas so that it may be detected in the event of a leak. The facilities include 475 miles of gas gathering pipelines, as well as dehydration, separation, regulation, odorization and metering equipment located at 62 stations. The gas gathering system is geographically dispersed and is located in 14 California counties. Approximately 120 MMcf per day of natural gas flows through our gas gathering system.

Interstate and Canadian Natural Gas Transportation Services Agreements

In 2003, approximately 67% 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 delivery of natural gas from western Canada to the United States-Canadian border with TransCanada NOVA Gas Transmission, Ltd. and TransCanada PipeLines Ltd., B.C. System. These companies pipeline systems connect at the border to the pipeline system owned by Gas Transmission Northwest Corporation which provides natural gas transportation services to interconnection points with our natural gas transportation system in the area of California near Malin, Oregon. We have a firm transportation agreement with Gas Transmission Northwest Corporation for these services.

During 2003, approximately 29% of our natural gas supplies came from the western United States, excluding California. We have firm transportation agreements with Transwestern and El Paso to transport this natural gas from supply points in this region to interconnection points 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 transportation agreements, including the contract quantities, contract durations and associated demand charges, net of sales of excess supplies, 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 recover these demand charges through the CPIM. We may, upon prior notice, extend each of these natural gas transportation agreements for additional minimum terms ranging, depending on the particular agreement, 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. If another prospective shipper also wants the capacity, we would be required to match the competing bid with respect to both price and term.

Pipeline	Expiration Date	Quantity MDth per day	Demand Charges for the Year Ended December 31, 2003
			(in millions)
El Paso Natural Gas Company	10/31/2003	100	$ 9.5
El Paso Natural Gas Company	12/31/2004	64	4.5
TransCanada NOVA Gas Transmission, Ltd.	12/31/2005	593	23.6
TransCanada PipeLines Ltd., B.C. System	10/31/2005	584	10.6
Gas Transmission Northwest Corporation	10/31/2005	610	55.0
Transwestern Pipeline Co.	03/31/2007	150	15.8
El Paso Natural Gas Company	03/31/2007	40	3.8
El Paso Natural Gas Company	04/30/2005	100	1.1

Competition

Historically, energy utilities operated as regulated monopolies within service territories where they were essentially the sole suppliers of natural gas and electricity services. These utilities owned and operated all of the businesses and facilities necessary to generate, transport and distribute energy. 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, the utilities undertook a continuing obligation to serve their customers, in return for which the utilities were 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 services 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, to varying degrees, have 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 late 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 standard market design proposal issued in July 2002 encourages unbundled transmission. The ISO also issued its own comprehensive market design proposal to effect changes to the structure and operation of the California electricity market, subject to the FERC s approval. The FERC has approved the first phase of the ISO s new rules and implementation of the first phase is expected to be completed in the second quarter of 2004. A later phase to establish integrated forward markets and locational marginal pricing and revise congestion management would be implemented in the future, if approved by FERC. The ISO is expected to file proposed tariff language with the FERC later in 2004 to address these issues. Both the timing and substance of the FERC s regional transmission organization policy and the FERC s and the ISO s market design processes may be affected if an energy bill is passed by Congress.

In July 2003, in order to limit opportunities for transmission providers to favor their own generation, facilitate market entry for generation competitors by streamlining and standardizing interconnection procedures, and encourage needed investment in generator and transmission infrastructure, the FERC issued final rules on the interconnection of generators larger than 20 MW with a transmission system. The rules will require regulated transmission providers, such as us or the ISO, generally to use standard interconnection procedures and a standard agreement for generator interconnections. These rules would require us and the ISO to revise the existing agreements and procedures used when constructing facilities to interconnect new generators. Numerous parties have requested rehearing and a stay of the generator interconnection rules. Although the FERC has not yet ruled on the requests for rehearing, the FERC has ordered that the rules will not become effective until after the FERC accepts new tariff changes to implement the rules. We, along with other transmission owners, filed proposed tariffs changes on January 20, 2004. It is uncertain when the FERC will act on the rehearing requests or the proposed tariff changes. Further the FERC s rulemaking on generator interconnections may be affected if an energy bill is passed by 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. AB 1890 also gave customers the choice of continuing to buy electricity from the California investor-owned electric utilities or, beginning in April 1998, entering into contracts to purchase electricity from alternate energy service providers (*i.e.*, becoming direct access customers). The CPUC suspended the right of retail end-user customers to become direct access customers on September 20, 2001. The CPUC has assessed an additional charge on certain direct access customers to avoid a shift of costs from direct access customers to customers who receive bundled service.

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 the DWR s and our costs. AB 117 also authorized us to recover from each community choice aggregator any costs of implementing the program that are reasonably attributable to the community choice aggregator, and to recover from ratepayers any costs of implementing the program not reasonably attributable to a community choice aggregator.

We face competition in the electricity distribution business as a result of the construction of duplicate distribution facilities to serve specific existing or new customers, condemnation of our distribution facilities by local governments or districts, self-generation by our customers and technological developments. These and other forms of competition 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 are 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 whether to provide electricity distribution services within our service territory. The City and County of San Francisco (along with other California communities) have been considering municipalization of our electricity distribution system within their jurisdictions. In addition, the Sacramento Municipal Utility District currently is considering annexing portions of our service territory, with the objective of enabling the district to replace us within these areas. Some existing public power entities, such as the Modesto and Merced Irrigation Districts, also are expanding their services in our service area. 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 a large commercial customer, 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 decline in our revenues.

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 pipeline companies must provide transportation service regardless of whether the customer (often a local gas distribution company) buys the natural gas commodity from these companies.

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 noncore customers purchase their natural gas from producers, marketers and brokers, and purchase their preferred mix of transportation, storage and distribution services from us. Although they can select the gas suppliers of their choice, substantially all core customers buy natural gas, as well as transportation and distribution services, from us as bundled service. The gas accord market structure has been extended by the CPUC through 2005.

We compete with other natural gas pipeline companies for customers transporting natural 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. The total delivered cost of natural gas includes, in addition to the commodity cost, transportation costs on all pipelines 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 amount that we charge for transportation 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 this expansion, the volume of natural gas that we deliver to the southern California market may decrease, although to date we have not experienced any significant decrease in our volumes shipped. We also compete for storage services with other third-party storage providers, primarily in northern California.

From time to time, existing pipeline companies propose to expand their pipeline systems for delivery of natural gas into northern and central California. As a result of the California energy crisis, several new natural gas pipeline proposals were initiated to serve proposed new generation facilities in 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 December 31, 2003, we had approximately 20,300 employees. Of our employees, approximately 13,500 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 SEIU. The ESC and IBEW collective bargaining agreements expire on December 31, 2007. The SEIU collective bargaining agreement expires on February 28, 2008.

Our 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 Natural Gas Utility Operations. In total, we occupy 9.3 million square feet, including approximately 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 settlement agreement with the CPUC. Approximately 44,000 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 Mechanisms section below summarize some of the more significant energy laws, regulations and regulatory mechanisms affecting us. These sections are not an exhaustive description of all the energy laws, regulations and regulatory proceedings that affect us. The energy laws, regulations and regulatory proceedings may change or be implemented or applied in a way that we do not currently anticipate. For discussion of specific regulatory proceedings affecting us, see Management s Discussion and Analysis of Financial Condition and Results of Operations.

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 electricity transmission, 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 of generation capacity. In addition, the FERC has jurisdiction over our electricity transmission revenue requirements and rates, the licensing of substantially all of our hydroelectric generation facilities and the interstate sale and transportation of natural gas.

In response to 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 (unless a generator could demonstrate that its costs justified a rate in excess of $250 per MWh) and established various automatic mitigation procedures. As of December 2003, all sellers with market-based rate authority became subject to, and incorporated in their market-based rate tariffs, behavioral conditions designed to prevent market manipulation.

In February 2004, the FERC is expected to consider ISO market monitoring and oversight in connection with the FERC s review of the ISO s standard market design proposals. Market monitoring and mitigation also may be affected if an energy bill is passed by Congress.

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 a 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.

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 aspects of the siting of the electricity 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. In addition, the CPUC 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 staggered 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. 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 electric utilities retail customers. AB 1X required the California investor-owned electric utilities, including us, to deliver that electricity and act as the DWR s billing and collection agent.

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

Senate Bill 1078. SB 1078, enacted in September 2002, created a renewable portfolio standard for investor-owned utilities that requires annual 1% increases of renewable electrical procurement purchases until renewable resources equal 20% of total retail sales in 2017.

In connection with the settlement agreement, we and Corp agreed to seek to refinance the remaining unamortized pre-tax balance of the $2.21 billion after-tax regulatory asset and associated federal, state and franchise taxes, up to a total of $3.0 billion, as expeditiously as practicable after the effective date of our plan of reorganization using a securitized financing supported by a dedicated rate component that would require enactment of authorizing California legislation. On January 22, 2004, the CPUC approved proposed legislation, Senate Bill 772, that would authorize a dedicated rate component to securitize the regulatory asset and the associated taxes. The California Assembly s Utilities and Commerce Committee approved the proposed legislation on February 2, 2004. The proposed legislation will next be considered by the California Assembly s Appropriations Committee. Any adopted legislation must be satisfactory to the CPUC, us and TURN, and the refinancing must not adversely affect our issuer or debt credit ratings among other conditions.

The California Energy Resources Conservation and Development Commission

The California Energy Resources Conservation and Development Commission, commonly called the CEC, is the state s lead energy policy agency. The CEC also is responsible for the siting of all thermal power plants over 49 MW and administers public interest research and development funds, as well as renewable resource programs, including the renewable energy portfolio standard program.

Other Regulation

We obtain a number of permits, authorizations and licenses in connection with the construction and operation of our generation facilities, electricity 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 some of the more 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 seven hydroelectric projects and one transmission line project undergoing FERC relicensing. We will begin relicensing proceedings on two additional hydroelectric projects within the next two years.

We have over 520 franchise agreements with various cities and counties that permit us to install, operate and maintain our electric, natural gas, oil and water facilities in 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, authorizations and licenses we have rights to occupy and/or use public property for the operation of our business and to conduct certain related operations.

Ratemaking Mechanisms

Overview

Transition from Frozen Rates to Cost of Service Ratemaking

Frozen electricity rates, which began on January 1, 1998, were designed to allow us to recover our authorized utility costs, and to the extent frozen rates generated revenues in excess of these costs, to recover our transition costs. Although the surcharges implemented in 2001 effectively increased the actual rate to customers, under the frozen rate structure, increases in our authorized revenue requirements did not increase our revenues. In addition, DWR revenue requirements reduced our revenues under the frozen rate structure. As a result of a January 2004 CPUC decision determining that the rate freeze ended on January 18, 2001, combined with the revised electricity rates that will be implemented as a result of the CPUC s approval of the rate design settlement, we expect that our rates will reflect cost of service ratemaking and rates will be calculated based on the aggregate of various authorized rate components. Changes in any individual revenue requirement will change customers electricity rate.

Revenue Requirements

Before the rates for our electricity and natural gas utility services can be set, 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 these 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 utility services, including a return of, and a fair rate of return on, its rate base. Revenue requirements are then allocated among customer classes and specific rates designed to produce the required revenue are established. In our rate cases, intervenors have the opportunity to comment on our application. The issues raised by these comments are then resolved by the appropriate regulatory agency. If we and the intervenors can settle these issues, these settlements are submitted to the regulatory agency for approval.

General Rate Cases

Our primary revenue requirement proceeding is the general rate case filed with the CPUC. In the GRC, the CPUC authorizes us to collect from customers an amount known as base revenues to recover base business and operational costs 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 requirements, the CPUC allocates revenue requirements among customer classes (mainly residential, commercial, industrial and agricultural) and establishes specific rate levels. Typical intervenors in our general rate case include the ORA and TURN.

Attrition Rate Adjustments

The CPUC may authorize us to receive annual increases in the base revenues authorized for the test year of a general rate case 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. These adjustments are known as attrition rate adjustments. Attrition rate adjustments provide increases in the revenue requirements that we are authorized to collect in rates for electricity and natural gas distribution and electricity generation operations.

Cost of Capital Proceedings

The CPUC generally conducts an annual cost of capital proceeding to determine our authorized capital structure and the authorized rate of return that we may earn on our electricity and natural gas distribution and electricity generation assets. The cost of capital proceeding establishes the percentage components that common equity, preferred equity and debt will represent in our total authorized capital structure for a specific year. The CPUC then establishes the authorized return on common equity, preferred equity and debt that we will have the opportunity to collect in our authorized rates. For 2005, this proceeding also will set the authorized rate of return for our gas transportation and storage assets.

Baseline Allowance

The CPUC sets and periodically revises a baseline allowance for our residential gas and electricity customers. A customer s baseline allowance is the amount of its monthly usage that is covered under the lowest possible natural gas or electricity rate. Electricity baseline usage is also exempt from certain surcharges. Natural gas or electricity usage in excess of the baseline allowance is covered by higher rates that increase with usage.

DWR Electricity and DWR Revenue Requirements

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 electric utilities retail end-user customers and to issue revenue bonds to finance electricity purchases. AB 1X also required us to deliver the electricity purchased by the DWR over our distribution system 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 its 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 through a revenue requirement. AB 1X also 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 from entering into new electricity purchase contracts and from purchasing electricity on the spot market after December 31, 2002. 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 electric utilities, including our customers. On September 19, 2002, the CPUC issued a decision allocating electricity from the DWR contracts to the customers of the three California investor-owned electric utilities. The DWR continues to be legally and financially responsible for these contracts. The electricity provided under 19 of the DWR contracts was allocated to our customers. We are responsible for scheduling and dispatching the electricity subject to the DWR allocated contracts on a least-cost basis and for many administrative functions associated with those contracts.

The DWR pays for its costs of purchasing electricity from a revenue requirement collected from electricity customers of the three California investor-owned electric utilities through what is known as a power charge. The DWR pays for its costs associated with its $11.3 billion bond offering completed in November 2002 from another revenue requirement collected from electricity customers through what is known as a bond charge. 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 implementation of the DWR s revenue requirement and to provide the DWR with funds to make its electricity purchases. Because we act as a billing and collection agent for the DWR, amounts collected for the DWR and any adjustments are not included in our revenues.

DWR Allocated Contracts

The DWR provided approximately 30% of the electricity delivered to our customers in 2003. The DWR purchased the electricity under contracts with various generators and through open market purchases. We are responsible for administration and dispatch of the DWR s electricity procurement contracts allocated to our customers, for purposes of meeting a portion of our net open position. The DWR remains legally and financially responsible for the electricity procurement contracts.

The contracts terminate at various times through 2012 and consist of must-take and capacity charge contracts. Under must-take contracts, the DWR must take and pay for electricity generated by the applicable generating facility regardless of whether the electricity is needed. Under capacity charge contracts, the DWR must pay a capacity charge but is not required to purchase electricity unless that electricity is dispatched and delivered.

The DWR has stated publicly that it intends to transfer full legal title to, and responsibility for, the DWR power purchase contracts to the California investor-owned electric utilities as soon as possible. However, the DWR power purchase contracts cannot be transferred to us without the consent of the CPUC. The 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 power purchase 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 S&P will be no less than A;
- the CPUC first makes a finding that, for purposes of assignment or assumption, the DWR power purchase contracts to be 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 power purchase contracts to be assumed without further review.

Procurement Resumption and Procurement Plans

On January 1, 2003, the California investor-owned electric utilities resumed responsibility for procuring electricity to meet their residual net open positions. They also became responsible for scheduling and dispatching the electricity subject to the DWR allocated contracts on a least-cost basis and for many administrative functions associated with those contracts. The utilities also were required by SB 1976 to submit short-term and long-term procurement plans to the CPUC for approval. In December 2003, the CPUC approved our short-term 2004 procurement plan. We have also received authority to enter into electricity purchase contracts of up to five years in duration to meet our residual net open position so long as we begin receiving electricity under these contracts during 2004. In the January 2004 CPUC decision discussed below, the CPUC also adopted short-term procurement authority for 2005 for the California investor-owned electric utilities in order to allow them to begin the normal cycle for procuring products required for summer 2005; however, contracts for 2005 cannot exceed one year.

Effective January 1, 2003, under California law we established the ERRA, a balancing account, designed to track and allow recovery of the difference between the recorded procurement revenues and actual costs incurred under our authorized procurement plans, excluding the costs associated with the DWR allocated contracts and certain other items. The CPUC must review the revenues and costs associated with an investor-owned utility s electricity procurement plan at least semi-annually and adjust retail electricity rates or order refunds, as appropriate, when the aggregate overcollections or undercollections exceed 5% of the utility s prior year electricity procurement revenues, excluding amounts collected for the DWR. These mandatory adjustments will continue until January 1, 2006. The CPUC s review of our procurement activities will examine our least-cost dispatch of our resource portfolio (including the DWR allocated contracts), fuel expenses for our electricity generation facilities, contract administration (including administration of the DWR allocated contracts) and our electricity procurement contracts. As a result of this review, some of our procurement costs could be disallowed.

Electricity Transmission

Our electricity 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 the 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.

FERC 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

- rates to recover ISO charges for both reliability service costs and an ISO charge associated with a ten-year shift from utility-specific transmission charges to an ISO grid-wide charge, both of which are discussed below.

We derive the majority of our transmission revenue from base transmission rates.

Transmission Control Agreement

We are a party to a TCA with the ISO and other participating transmission owners. As a transmission owner, we are required to give two years notice and receive regulatory approval if we wish to withdraw from the TCA. Under this agreement, the transmission owners, which also include SCE, San Diego Gas & Electric Company and several municipal utilities, assign operational control of their electricity transmission systems to the ISO. In addition, as a party to the TCA, we are responsible for a share of the costs of RMR agreements between the ISO and owners of the RMR plants. We are also an owner of some of these RMR plants for which we receive revenue from the ISO. Under the RMR agreements, RMR plants must remain available to generate electricity when needed for local transmission system reliability upon the ISO s demand.

Reliability Services Costs

The ISO bills us for reliability services based on payments that the ISO makes to generators under RMR agreements and to others to support reliability of our transmission system. The costs of RMR agreements attributed to supporting our historic transmission control area are charged to us as a participating transmission owner. These costs were approximately $330 million in 2003. Under our transmission owner tariff, we charge our customers rates designed to recover these reliability service charges, without mark-up or service fees. We track costs and revenues related to reliability services in the reliability services balancing account. Periodically, our electricity transmission rates are adjusted to refund over-collections to our customers or to collect any under-collections from customers.

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 intended to reimburse other transmission owners who are generally new ISO participants, whose costs are higher than that embedded in the uniform rate. Under the ISO s application, our obligation for this cost differential would be capped at $32 million per year during the ten-year transition period. A hearing in this matter was conducted at the FERC in October and November 2003 and an initial decision from the presiding administrative law judge is scheduled to be issued in March 2004.

Natural Gas

The Gas Accord

In 1998, we implemented the gas accord, under which our natural gas transportation and storage services were separated for ratemaking purposes from our distribution services. The gas accord established natural gas transportation rates and natural gas storage rates. On December 18, 2003, the CPUC approved our application to retain the gas accord market structure for 2004 and 2005 and resolved the rates, and terms and conditions of service for our natural gas transportation and storage system for 2004. We continue to be at risk of not recovering our natural gas transportation and storage costs and do not have regulatory balancing account protection for overcollections or undercollections of natural gas transportation or storage revenues.

Biennial Cost Allocation Proceeding

Our natural gas distribution costs and balancing account balances are allocated to customers in the biennial cost allocation proceeding. This proceeding is updated in the interim year for purposes of adjusting natural gas rates to recover from customers any undercollection, or refund to customers any overcollection, in the balancing accounts. Balancing accounts for natural gas and public purpose program revenue requirements accumulate differences between authorized revenue requirements and actual base revenues.

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 undercollections and overcollections taken into account in subsequent monthly rates.

Under the CPIM, our natural gas purchase costs (including Canadian and interstate capacity and volumetric transportation charges) 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 between 99% and 102% of the benchmark, are considered reasonable and fully recoverable, in customers rates. One-half of the costs above 102% of the benchmark are recoverable in customers rates, and our customers receive three-fourths of the savings when the costs are below 99% of the benchmark. Any awards associated with CPIM are reflected annually in the purchased natural gas balancing account after the close of the annual period ending October 31 that is used to measure the CPIM. These awards are not included in earnings until approved by the CPUC.

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 by the FERC in a ratemaking review process and the Canadian tariffs are approved 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. Natural gas is transported pursuant to these agreements from the points at which we take delivery of natural gas typically in Canada 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 certain California 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 these California 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 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 after 1997. In January 2004, the CPUC approved a settlement with TURN that allows us to fully recover Transwestern costs retroactive to July 2003.

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. In January 2004, the CPUC re-allocated all the costs, including Transwestern costs incurred since July 2003, to our core customers, because the pipeline capacity is used to serve core customers. Our noncore customers and core aggregation customers will receive a refund or bill credit for El Paso capacity costs paid by these customers between March 2003 and January 2004.

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, 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.

Generally, we have recovered the costs of complying with environmental laws and regulations in our rates, subject to reasonableness review. Environmental costs associated with sites that contain hazardous wastes are subject to a special ratemaking mechanism.

In 1994, the CPUC established a ratemaking mechanism under which we are authorized to recover hazardous waste remediation costs for environmental claims (*e.g.*, for cleaning up our facilities and sites where we have sent hazardous substances) from customers. That mechanism allows us to include 90% of the hazardous waste remediation costs in our rates without review.

Ten percent of any insurance recoveries associated with hazardous waste remediation sites are assigned to our customers. The balance of any insurance recoveries (90%) are retained by us until we have been reimbursed for the 10% share of clean-up costs not included in rates. There also is a special sharing between our customers and us of the costs incurred pursuing recovery under insurance contracts. In connection with electricity industry restructuring, this mechanism may no longer be used to recover electricity generation-related clean-up costs for contamination caused by events occurring after January 1, 1998. We cannot provide assurance, however, that these costs will not be material, or that we will be able to recover our costs in the future.

Hazardous waste remediation costs in the future are likely to be significant. However, based on our past experience, we believe that we can recover most of these costs either in rates or through insurance claims.

Air Quality

Our operations, most significantly our generation plants and natural gas 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, sulfur 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. These initiatives include limits on the emissions of nitrogen oxide, sulfur dioxide, mercury and carbon dioxide, and some would allow the use of trading mechanisms to achieve or maintain compliance with the proposed rules. Hearings on legislation to amend the federal Clean Air Act have been held in the U.S. Senate but not in the House of Representatives.

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. Two of the local air districts in which we own and operate fossil fuel-fired generation facilities have adopted final rules under the California Clean Air Act and the federal Clean Air Act that required reductions in nitrogen oxide emissions from the facilities of approximately 90% by 2004. We are in compliance with these rules. Several other air districts are considering nitrogen oxide rules that would apply to our 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 which we expect to recover through rates.

In addition, current regulatory initiatives, particularly at the federal level, could increase our compliance costs and capital expenditures primarily with respect to our gas transportation facilities, fleet and fuel storage tanks, to comply with laws relating to emissions of carbon dioxide and other greenhouse gases, particulates and other toxic pollutants. If enacted, these laws could require us to replace equipment, install additional pollution controls, purchase various emission allowances, or curtail operations. Although associated costs and capital expenditures could be material, we expect that we would be able to recover these costs and capital expenditures in rates.

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 National Pollutant Discharge Elimination System, or NPDES, permit issued by the Central Coast Regional Water Quality Control Board, or Central Coast Board. This permit allows the 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, the 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 the 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, we have 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. On June 17, 2003, the Central Coast settlement was executed by us, the Central Coast Board and the California Attorney General s Office. A condition to the effectiveness of the Central Coast settlement is that the Central Coast Board renew Diablo Canyon s NPDES permit. However, at its July 10, 2003 meeting, the Central Coast Board did not renew the NPDES permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported this settlement 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 proceeding on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with the Diablo Canyon power plant s operation of its cooling water system. We are seeking withdrawal of this claim from our Chapter 11 proceeding.

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, Hunters Point and Humboldt Bay power plants 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. The final regulations were issued in February 2004 and our initial review suggests that no material increased costs will result.

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. We are seeking to secure habitat conservation plans to ensure long-term compliance with the state and federal endangered species acts. We expect that we will be able to recover costs of complying with state and federal endangered species acts through rates.

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 the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, or 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 (or have done so in the past). 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 are currently 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 $8 million in 2003 and expect to spend approximately $6 million in 2004 on these 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. We have not incurred any significant costs associated with these non-owned sites, but it is possible that we may incur additional cleanup costs related to these sites in the future if hazardous substances for which we have liability are found.

In mid-January 2004, hexavalent chromium was detected in a sample taken from a groundwater monitoring well near our natural gas compressor station located in the area of California near Topock, Arizona. This monitoring well is located approximately 150 feet from the Colorado River. While hexavalent chromium had been detected during previous sampling of other monitoring wells located further from the river, previous samples from this well had not shown any detectable hexavalent chromium. We are cooperating with the California Department of Toxic Substances Control, or DTSC, other state agencies and appropriate federal agencies to develop a plan to ensure that the hexavalent chromium does not impact the Colorado River. Although implementation of the plan poses several technical and regulatory obstacles, we do not expect the outcome in this matter to have a material adverse effect on our results of operations or financial condition.

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 waste from our facilities, or to pay for associated cleanup costs or natural resource damages. We are currently aware of nine sites where investigation or cleanup activities are currently underway. 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 it may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure using current technology, enacted laws and regulations, experience gained at similar sites and 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 end of the cost range using reasonably possible outcomes least favorable to us.

We had an undiscounted environmental remediation liability of approximately $314 million at December 31, 2003, and $331 million at December 31, 2002. During 2003, the liability was reduced by approximately $17 million mainly due to reassessment of the estimated cost of remediation and remediation payments. The approximately $314 million accrued at December 31, 2003, includes approximately $104 million related to the pre-closing remediation liability associated with divested generation facilities, and $210 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 manufactured gas plant sites. Of the approximately $314 million environmental remediation liability, approximately $147 million has been included in prior rate setting proceedings, and we expect that approximately $116 million will be allowable for inclusion in future rates. We also recover our costs from insurance carriers and from other third parties whenever possible. Any amounts collected in excess of our ultimate obligations may be subject to refund to ratepayers.

Our undiscounted future costs could increase to as much as $422 million if the other potentially responsible parties are not financially able to contribute to these costs or the extent of contamination or necessary remediation is greater than anticipated. The $422 million amount does not include an estimate for the costs of remediation at known sites owned or operated in the past by our predecessor corporations for which we have not been able to determine whether liability exists.

The California Attorney General, on behalf of various state environmental agencies, filed claims in our Chapter 11 proceeding 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 remediation or cleanup actions. Our plan of reorganization provides that we intend to respond to these types of claims in the ordinary course of business and since we have not argued that our Chapter 11 proceeding relieves us of our obligations to respond to valid environmental remediation orders, we believe the California Attorney General s claims seeking specific cash recoveries are unenforceable. Environmental claims in the ordinary course of business will not be discharged in our Chapter 11 proceeding and will pass through our Chapter 11 proceeding unimpaired.

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. The DOE has been unable to meet its contractual commitment to begin accepting spent fuel. First, there was a delay in identifying a storage site. Then, after the DOE selected Yucca Mountain, Nevada for the site, protracted litigation has prevented the DOE from constructing the storage facility. The DOE s current estimate for an available site to begin accepting physical possession of the spent nuclear fuel is 2010. However, considerable uncertainty exists regarding when the DOE will begin to accept spent fuel for storage or disposal. Under our contract with the DOE, if the DOE completes a storage facility by 2010, the earliest Diablo Canyon s spent fuel would be accepted for storage or disposal would be 2018.

On January 22, 2004, we filed separate complaints in the U.S. Court of Federal Claims against the DOE alleging that the DOE has breached its contractual obligation to move spent nuclear fuel from Diablo Canyon and Humboldt Bay Unit 3 to a national repository beginning in 1998. The complaints seek recovery of our costs incurred for the planning and development of on-site storage at both facilities as a result of the DOE s failure to meet its obligations. Our complaints are similar to complaints filed by at least 20 other utilities with nuclear facilities.

Under current operating procedures, we believe that the Diablo Canyon power plant s existing spent fuel pools have sufficient capacity to enable it to operate through approximately 2007. It is unlikely that an interim or permanent DOE storage facility will be available by 2007. Therefore, we have applied to the NRC for a license to build an on-site dry cask storage facility to store spent fuel at the Diablo Canyon power plant, pending disposal or storage at a DOE facility. The NRC has provided initial approvals for the facility and is expected to complete our authorization process in early 2004. We also have initiated the process for obtaining a required California Costal Commission permit for the facility. If the dry cask storage facility is not approved or is delayed, we also are pursuing NRC approval of another storage option to install a temporary rack in each unit that would increase the on-site storage capability to permit us to operate Unit 1 until 2010 and Unit 2 to 2011. During this additional period of time, we also would pursue NRC approval for a high density reracking of both units, which, if approved, would allow us to operate both units until shortly before the licenses expire in 2021 for Unit 1 and 2025 for Unit 2. If we are unsuccessful in permitting and constructing the on-site dry cask storage facility, and we are otherwise unable to increase our on-site storage capacity, it is possible that the operations of Diablo Canyon may have to be curtailed or halted until such time as spent fuel can be safely stored.

In July 1988, the NRC gave us final approval to store radioactive waste from our retired nuclear generating facility, Humboldt Bay Unit 3, on-site before decommissioning the unit is completed in 2015. 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, 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 filed an application in December 2003 with the NRC seeking authorization to build an on-site dry cask storage facility at Humboldt Bay Unit 3. We plan to file an application with the California Coastal Commission for a permit to build the 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

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. Our nuclear power facilities consist of two units at the Diablo Canyon power plant and the retired facility at Humboldt Bay Unit 3. For ratemaking purposes, the eventual decommissioning of Diablo Canyon Unit 1 is scheduled to begin in 2021 and to be completed in 2040, decommissioning of Diablo Canyon Unit 2 is scheduled to begin in 2025 and to be completed in 2041, and decommissioning of Humboldt Bay Unit 3 is scheduled to begin in 2006 and be completed in 2015.

The estimated nuclear decommissioning costs for the Diablo Canyon power plant and Humboldt Bay Unit 3 are approximately $1.83 billion in 2003 dollars (or approximately $5.25 billion in future dollars). These estimates are based on a 2002 decommissioning cost study prepared in accordance with CPUC requirements and used in our nuclear decommissioning costs triennial proceeding, discussed below. 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.

The CPUC has established the nuclear decommissioning costs triennial proceeding to determine our estimated decommissioning costs and to establish the associated annual revenue requirement and escalation factors for consecutive three-year periods. In October 2003, the CPUC issued a decision in the 2002 nuclear decommissioning costs triennial proceeding (covering 2003 through 2005) finding that the funds in the Diablo Canyon nuclear decommissioning trusts are sufficient to pay for the Diablo Canyon power plant s eventual decommissioning. The decision also set the annual decommissioning fund revenue requirement for Humboldt Bay Unit 3 at approximately $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 of approximately $8.3 million for Humboldt Bay Unit 3 SAFSTOR operating and maintenance costs. The total adopted annual revenue requirement of approximately $26.7 million represents a $4.5 million decrease from the previously adopted revenue requirement of approximately $31.2 million, which included amounts for both Humboldt Bay Unit 3 and Diablo Canyon. The CPUC also ordered us to partially fund our 2004 revenue requirement with approximately $10 million that we collected in rates in 2000 for our nuclear decommissioning revenue requirement but that we did not contribute to the trusts due to our cash conservation needs during the energy crisis.

Our revenue requirements for nuclear decommissioning costs are recovered from ratepayers through a nonbypassable charge that will continue until those costs are fully recovered. Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. We have three decommissioning trusts for our Diablo Canyon and Humboldt Bay Unit 3 nuclear facilities. We have elected that two of these trusts be treated under the Internal Revenue Code of 1986, as amended, or the Code, as qualified trusts. If certain conditions are met, we are allowed a deduction for the payments made to the qualified trusts. These payments cannot exceed the amount collected from ratepayers through the decommissioning charge. The qualified trusts are subject to a lower tax rate on income and capital gains, thereby increasing the trusts after-tax returns. Among other requirements, to maintain the qualified trust status, the IRS, must approve the amount to be contributed to the qualified trusts for any taxable year. The remaining non-qualified trust is exclusively for decommissioning Humboldt Bay Unit 3. We cannot deduct amounts contributed to the non-qualified trust until the decommissioning costs are actually incurred.

In 2003, we collected approximately $22.6 million in rates and contributed approximately $21.3 million, on an after-tax basis, to the nuclear decommissioning trusts. For 2004, we are authorized to collect approximately $18.5 million in rates for decommissioning Humboldt Bay Unit 3. Of this amount, we expect to contribute approximately $13.3 million, on an after-tax basis, to the qualified and non-qualified trusts for Humboldt Bay Unit 3. We have requested the IRS approve the new amounts to be contributed to the qualified trusts for Humboldt Bay Unit 3. If the IRS does not approve the request, we must withdraw any contributions it made to the qualified trusts for 2003 and contribute the withdrawn amounts, on an after-tax basis, to the non-qualified trust. We would likely request that the CPUC approve an increase in revenue requirements to make up for the reduced amount contributed to the non-qualified trust due to the reduced rate of return attributable to taxes

The funds in the decommissioning trusts, along with accumulated earnings, will be used exclusively for decommissioning and dismantling our 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 decommissioning trusts until authorized by the CPUC. At December 31, 2003, we had accumulated decommissioning trust funds with an estimated fair value of approximately $1.4 billion, based on quoted market prices and net of deferred taxes on unrealized gains.

Electric and Magnetic Fields

EMFs naturally result from the generation, transmission, distribution and use of electricity. In January 1991, the CPUC opened an investigation 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 or 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. Michael Peevey, et al.

On November 8, 2000, we filed a lawsuit in the district court against the CPUC commissioners. In this lawsuit, we seek 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.

Our complaint alleges that the wholesale electricity costs that we had 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 asserts claims under the Commerce Clause and the Due Process Clause of the U.S. Constitution. On January 29, 2001, our lawsuit was transferred to the U.S. District Court for the Central District of California, or the central district court, where a similar lawsuit filed by SCE was pending. On May 2, 2001, the central district court dismissed our complaints 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 district court 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 district 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 United States Circuit Court of Appeals for the Ninth Circuit, or the Ninth Circuit. Pursuant to our request, the district court 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 district court s proceedings pending the CPUC s appeal. The appeal was fully briefed and the Ninth Circuit heard oral argument on March 10, 2003.

Under the settlement agreement, we will dismiss the filed rate case with prejudice on or as soon as practicable after the later of the effective date of our plan of reorganization or the date on which CPUC approval of the settlement agreement is no longer subject to appeal. Therefore, we filed a motion to stay consideration of the appeal of the filed rate case. On August 11, 2003, the Ninth Circuit issued an order staying proceedings in the filed rate case. The Ninth Circuit has ordered the parties to file a status report by July 30, 2004.

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. Grynberg (referred to as a relator in the terminology 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 Department of Justice, or 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 proceeding 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 the 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, 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. On June 17, 2003, the Central Coast settlement was executed by us, the Central Coast Board and the California Attorney General s Office. A condition to the effectiveness of the settlement is that the Central Coast Board 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 Central Coast settlement 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 proceeding on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with the 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 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 proceeding on behalf of DTSC and, in February 2004, withdrew 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. Corp, 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 proceeding, 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, loss of consortium, 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. Plaintiffs counsel selected ten of these initial trial plaintiffs, defense counsel selected seven of the plaintiffs, and one plaintiff and two alternates were selected at random. We have filed 13 summary judgment motions or motions in limine (motions to exclude potentially prejudicial information) challenging the claims of the trial test plaintiffs. Two of these motions are scheduled for hearing in the first quarter of 2004, with the others to be scheduled thereafter. The trial of the test cases is scheduled to begin in March 2004. Our motion to dismiss the complaint in the *Adams* case was granted. The plaintiffs in that case have until April 12, 2004 to file an amended complaint.

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.

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 Corp and its directors, as well as against our directors, based on allegations of unfair or fraudulent business acts or practices in violation of California Business and Professions Code Section 17200, or Section 17200. Among other allegations, the California Attorney General alleged that past transfers of money from us to Corp, and allegedly from Corp to other affiliates of Corp, violated various conditions established by the CPUC in decisions approving the holding company formation. The California Attorney General also alleged that the December 2000 and January and February 2001 ringfencing transactions, by which Corp subsidiaries complied with credit rating agency criteria to establish independent credit ratings, violated the holding company conditions. On January 9, 2002, the CPUC issued a decision interpreting the holding company condition regarding capital requirements (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 major 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 major California investor-owned utilities and their parent holding companies appealed the CPUC s interpretation of the first priority condition to various state appellate courts. The CPUC moved to consolidate all proceedings in the San Francisco state appellate court. The CPUC s request for consolidation was granted and all the petitions are now before the California Court of Appeal for the First Appellate District in San Francisco, California. Oral argument is scheduled for March 5, 2004.

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 Section 17200, a total penalty of not less than $500 million and costs of suit. 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 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 Corp s participation in our 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 June 2002 order to the district court.

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 proceeding. Corp and the directors named in the complaint have filed motions to strike certain allegations of the amended complaint. On February 28, 2003, the court denied the three 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 cases was more fully developed.

On February 11, 2002, a complaint entitled *City and County of San Francisco; People of the State of California v. PG&E Corporation, and Does 1-150,* was filed in San Francisco Superior Court. The complaint contains some of the same allegations contained in the California Attorney General s complaint, including allegations of unfair competition. In addition, the complaint alleges causes of action for conversion, claiming that Corp took at least $5.2 billion from the Utility, and for unjust enrichment. The City seeks injunctive relief, the appointment of a receiver, payment to customers, disgorgement, the imposition of a constructive trust, civil penalties and costs of suit.

After removing the City s action to the bankruptcy court in February 2002, Corp filed a motion to dismiss the complaint. Subsequently, the City filed a motion to remand the action to state court. In June 2002, the bankruptcy court issued an Amended Order on Motion to Remand stating that the bankruptcy court retained jurisdiction over the causes of action for conversion and unjust enrichment, finding that these claims belong solely to us and cannot be asserted by the City and County, but remanding the Section 17200 cause of action to state court. Both parties appealed the bankruptcy court s remand order to the district court.

In addition, a third 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 Corp and us 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, 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 mentioned above as to the California Attorney General s and the City s cases, the bankruptcy court retained jurisdiction over Behr s fraudulent transfer claim and bulk sales claim, finding them to belong to our estate. The bankruptcy court remanded Behr s Section 17200 claim to the Santa Clara Superior Court. Both parties appealed the bankruptcy court s remand order to the district court.

The San Francisco Superior Court has coordinated the California Attorney General s case with the cases filed by the City and County of San Francisco and Cynthia Behr.

On July 24, 2003, the district court heard oral argument on the appeal and cross-appeal of the bankruptcy court s remand order in the three cases. On October 8, 2003, the district court 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 district court found that these claims, estimated along with the City and County of San Francisco s claims at approximately $5 billion, are the property of our Chapter 11 estate and therefore are properly within the bankruptcy court s jurisdiction. Under our plan of reorganization, we would release these claims. The district court 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 Section 17200 could be resolved in San Francisco Superior Court, where a status conference has been scheduled for April 21, 2004. The California Attorney General and the City and County of San Francisco have appealed this ruling to the Ninth Circuit. The defendants have filed motions to dismiss the appeals. No proceedings have been scheduled in bankruptcy court regarding the restitution claims. Under Section 17200, the California Attorney General is entitled to seek civil penalties of $2,500 against each defendant for each violation of Section 17200. The

California Attorney General s complaint asserted that the total civil penalties would be not less than $500 million. The bankruptcy court s confirmation order provides that the California Attorney General s and the City and County of San Francisco s claims will not be released in connection with the implementation of our plan of reorganization.

The defendants filed a motion to seek clarification from the district court regarding whether the district court s October 2003 order reaches the restitution claims against the director defendants, as distinct from Corp. At a hearing in November 2003, the district court confirmed that its October 2003 order holds that the defendants restitution claims against the directors are also the property of our estate.

MANAGEMENT

As of March 1, 2004, 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.	61	Chairman of the Board
David R. Andrews	62	Director
Leslie S. Biller	55	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
Thomas B. King	42	Senior Vice President and Chief of Utility Operations
Roger J. Peters	53	Senior Vice President and General Counsel
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. (food and beverage businesses), and has held that position since February 2002. Prior to 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 serves as a director of UnionBanCal Corporation.

Leslie S. Biller has been one of our directors and a director of Corp since 2004. Mr. Biller is retired Vice Chairman and Chief Operating Officer of Wells Fargo & Company (financial services and retail banking). He held that position from November 1998 until his retirement in October 2002. Mr. Biller was President and Chief Operating Officer of Norwest Corporation (bank holding company) from 1997 until it merged with Wells Fargo & Company in 1998. Mr. Biller has been our advisory director and an advisory director of Corp since January 2003. He also serves as a director of Ecolab Inc.

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. and J.P. Morgan Chase Bank, responsible for its investment bank, investment management and private banking, and has held that position since January 2001. Prior to the merger with J.P. Morgan & Co. Incorporated, he was Vice Chairman of The Chase Manhattan Corporation (bank holding company) from August 2000 to December 2000. He was a partner in the Beacon Group, L.P., (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 serves as a 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 serves as 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 is retired 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 serves as a director of Agilent Technologies Inc. and McKesson Corporation.

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. Prior to that date, she was Dean of University Extension, University of California, Berkeley from July 1991 to June 1998. She also serves as 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 served as Vice Chairman of Ford Motor Company from October 2001 to July 2003. He is retired Chairman of the Board and Chief Executive Officer of Wells Fargo & Company (bank holding company) and Wells Fargo Bank, N.A. He was an executive officer of Wells Fargo Bank, N.A. from 1978 until his retirement in December 1994. He also serves as a director of ConAgra Foods, Inc. and Ford Motor Company.

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

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.

Thomas B. King has been our Senior Vice President and Chief of Utility Operations since November 2003. Prior to his election, Mr. King was a Senior Vice President of Corp from January 1999 to October 2003.

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.

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 SENIOR SECURED BONDS

This prospectus describes certain general terms of the senior secured bonds, or senior bonds, that we may sell from time to time under this prospectus. We will describe the specific terms of each series of senior bonds we offer in a prospectus supplement. The senior bonds will be issued under an indenture of mortgage and one or more supplemental indentures that we will enter into with BNY Western Trust Company, as trustee. We refer to the indenture of mortgage, as supplemented by various supplemental indentures that we will enter into with the trustee, as the indenture. We have summarized selected provisions of the indenture and the senior bonds below. The information we are providing you in this prospectus concerning the senior bonds and the indenture 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 indenture, including the forms of senior bonds attached thereto. You should consult the senior bonds themselves and the indenture for more complete information on the senior bonds as they, and not this prospectus or any prospectus supplement, govern your rights as a holder. The indenture is filed as an exhibit to the registration statement of which this prospectus is a part. The indenture will be qualified under the Trust Indenture Act of 1939, as amended, or the Trust Indenture Act, and the terms of the senior bonds will include those made part of the indenture by the Trust Indenture Act.

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 except as expressly provided.

General

After the effective date of our plan of reorganization, the indenture will constitute a first lien, subject to permitted liens, on substantially all of our real property and certain tangible personal property related to our facilities. The indenture does not limit the amount of debt that we may issue under it. However, prior to the release date, we may issue senior bonds under the indenture only on the basis of, and to the extent we have available, property additions, retired senior bonds and cash. In addition, prior to the release date, we may issue senior bonds under the indenture only if our net income for 12 consecutive calendar months during a specified period prior to the issuance of those senior bonds has not been less than two times our annual interest requirements. See Issuance of Additional Senior Bonds Prior to the Release Date. The lien securing the senior bonds may be released in certain circumstances, subject to certain conditions. Upon release of the lien, the senior bonds will cease to be our secured obligations and will become our general unsecured obligations ranking *pari passu* with our other senior unsecured indebtedness. See Discharge of Lien; Release Date. The senior bonds will be entitled to the benefit of the indenture equally and ratably with all other senior bonds issued under the indenture.

The prospectus supplement applicable to each issuance of senior bonds will specify, among other things:

- the title of the senior bonds;
- any limitation on the aggregate principal amount of the senior bonds;
- the price or prices at which we will sell the senior bonds;
- the date or dates on which the principal of any of the senior bonds 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 senior bonds, if any, which may be fixed or variable, or the method or means by which the interest rate or rates are to be determined, 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 senior bonds and the regular record date, if any, 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 senior bonds may be redeemed, in whole or in part, at our option;

any obligation of ours to redeem, purchase or repay any of the senior bonds 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 senior bonds will be so redeemed, purchased or repaid;

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

whether we will offer the senior bonds 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 senior bonds may be determined with reference to an index or other fact or event ascertainable outside the indenture, the manner in which such amount will be determined;

any events of default applicable to that series of senior bonds in addition to the events of default described under Events of Default;

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 senior bonds will be payable if other than U.S. dollars and the manner for determining the equivalent principal amount in U.S. dollars;

provisions, if any, for exchange of the certificates representing the senior bonds or changes to the title and CUSIP number of the senior bonds to reflect the release of the lien of the indenture on the release date;

if the principal of the senior bonds is payable from time to time without presentation or surrender, any method or manner of calculating the principal amount that is outstanding at any time for all purposes of the indenture; and

any other terms of the senior bonds.

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

Redemption

Any terms for the optional or mandatory redemption of a series of senior bonds will be set forth in a prospectus supplement for the offered series. Unless otherwise indicated in a prospectus supplement, senior bonds 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 senior bonds of a series are to be redeemed, the particular senior bonds to be redeemed will be selected by the method provided for in the prospectus supplement for that particular series, or in the absence of any such provision, by the trustee in the manner 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 trustee or a paying agent on or before the redemption date or we have directed the trustee or paying agent not to apply money deposited with it for redemption of senior bonds, we will not be required to redeem the senior bonds on the redemption date.

Lien of the Indenture

General

After the effective date of our plan of reorganization, the indenture will constitute a first lien, subject to permitted liens, on substantially all of our real property and certain tangible personal property related to our facilities. We refer to property that is subject to the lien of the indenture as mortgaged property and property that is excepted from the lien of the indenture as excepted property. The lien securing the senior bonds may be released, however, in certain circumstances and subject to certain conditions. Upon release of the lien, the senior bonds will cease to be our secured obligations and will become our general unsecured obligations ranking *pari passu* with our other senior unsecured indebtedness. See Discharge of Lien; Release Date.

The indenture provides that after-acquired property (other than after-acquired property qualifying as excepted property) located in the state of California will be subject to the lien of the indenture; provided, however, that in the case of a consolidation or merger (whether or not we are the surviving corporation) or the transfer or lease of all or substantially all of the mortgaged property, the indenture will not be required to be a lien upon any of the properties then owned or thereafter acquired by the successor corporation except properties acquired from us in or as a result of that transaction, to the extent not constituting excepted property, and improvements, extensions and additions to those properties and renewals, replacements and substitutions of or for any part or parts thereof. In addition, after-acquired property may be subject to liens existing or placed thereon at the time of acquisition thereof, including, but not limited to, purchase money liens, and, in certain circumstances, liens attaching to the property prior to the recording or filing of an instrument specifically subjecting the property to the lien of the indenture.

The indenture provides that before the release date, the trustee shall have a lien, prior to the senior bonds, on the mortgaged property and on all other property and funds held or collected by the trustee, other than property and funds held in trust for the payment of principal, premium, if any, and interest on the senior bonds, as security for the payment of the trustee s reasonable compensation and expenses, and as security for the performance by us of our obligation to indemnify the trustee against certain liabilities.

Without the consent of the holders, we and the trustee may enter into supplemental indentures in order to subject additional property to the lien of the indenture (including property which would otherwise be excepted property). This property would thereupon constitute property additions (so long as it would otherwise qualify as property additions as described below) and be available as a basis for the issuance of additional senior bonds. See Issuance of Additional Senior Bonds Prior to the Release Date.

See Discharge of Lien; Release Date below for a discussion of the provisions of the indenture pursuant to which the lien of the indenture may be discharged and the senior bonds may become our unsecured obligations.

Excepted Property

After the effective date of our plan of reorganization, the indenture will constitute a first lien, subject to permitted liens, on substantially all of our real property and certain tangible personal property related to our facilities, except for the following excepted property:

all money, investment property and deposit accounts (as those terms are defined in the California Commercial Code as in effect on the date of execution of the indenture), and all cash on hand or on deposit in banks or other financial institutions, shares of stock, interests in general or limited partnerships or limited liability companies, bonds, notes, other evidences of indebtedness and other securities, of whatever kind and nature, in each case to the extent not paid or delivered to, deposited with or held by the trustee;

all accounts, chattel paper, commercial tort claims, documents, general intangibles (with certain exclusions such as licenses and permits to use the real property of others), instruments, letter-of-credit rights and letters of credit (as those terms are defined in the California Commercial Code) and all contracts, leases (other than the lease of certain real property at our Diablo Canyon power plant), operating agreements and other agreements of whatever kind and nature; all contract rights, bills and notes;

all revenues, income and earnings, all accounts receivable, rights to payment and unbilled revenues, and all rents, tolls, issues, product and profits, claims, credits, demands and judgments, including any rights in or to rates, revenue components, charges, tariffs, or amounts arising therefrom, or in any amounts that are accrued and recorded in a regulatory account for collections by us;

all governmental and other licenses, permits, franchises, consents and allowances including all emission allowances (or similar rights) created under any similar existing or future law relating to abatement or control of pollution of the atmosphere, water or soil, other than all licenses and permits to use the real property of others, franchises to use public roads, streets and other public properties, rights of way and other rights, or interests relating to the occupancy or use of real property;

all patents, patent licenses and other patent rights, patent applications, trade names, trademarks, copyrights and other intellectual property, including computer software and software licenses;

all claims, credits, choses in action, and other intangible property;

all automobiles, buses, trucks, truck cranes, tractors, trailers, motor vehicles and similar vehicles and movable equipment; all rolling stock, rail cars and other railroad equipment; all vessels, boats, barges and other marine equipment; all airplanes, helicopters, aircraft engines and other flight equipment; and all parts, accessories and supplies used in connection with any of the foregoing;

all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; all materials, supplies, inventory and other items of personal property that are consumable (otherwise than by ordinary wear and tear) in their use in the operation of the mortgaged property; all fuel, whether or not that fuel is in a form consumable in the operation of the mortgaged property, including separate components of any fuel in the forms in which those components exist at any time before, during or after the period of the use thereof as fuel; all hand and other portable tools and equipment; and all furniture and furnishings;

all personal property the perfection of a security interest in which is not governed by the California Commercial Code;

all oil, gas and other minerals (as those terms are defined in the California Commercial Code) and all coal, ore, gas, oil and other minerals and all timber, and all rights and interests in any of the foregoing, whether or not the minerals or timber have been mined or extracted or otherwise separated from the land; and all electric energy and capacity, gas (natural or artificial), steam, water and other products generated, produced, manufactured, purchased or otherwise acquired by us;

all property which is the subject of a lease agreement designating us as lessee and all our right, title and interest in and to that leased property and in, to and under that lease agreement, whether or not that lease agreement is intended as security (other than certain real property leased at our Diablo Canyon power plant);

all property, real, personal and mixed, which subsequent to the execution date of the indenture, has been released from the lien of the indenture, and any improvements, extensions and additions to those properties and renewals, replacements and substitutions of or for any parts thereof;

all property, real, personal and mixed, that is stated in the indenture to not be subject to the lien of the indenture; and

all proceeds (as that term is defined in the California Commercial Code) of the property listed in the preceding bullet points;

provided, however, that excepted property shall not include the identifiable proceeds (as that term is defined in the California Commercial Code) of any mortgaged property that we have disposed of in violation of the terms of the indenture.

If an event of default occurs under the indenture before the release date, certain of the excepted property may become subject to the lien of the indenture.

The indenture permits us to create or allow to exist certain permitted liens, such as mortgages, deeds of trust, pledges, security interests, leases, reservations, restrictions, charges, encumbrances, or other liens on the mortgaged property which rank senior to the lien of the indenture.

Permitted liens include:

to the extent we consolidate with, or merge into, another entity, liens on the assets of that entity in existence on the date of the consolidation or merger and securing debt of that entity, provided that the debt and liens were not created or incurred in anticipation of the consolidation or merger and do not extend to any other mortgaged property in existence immediately prior to the consolidation or merger;

as to property acquired by us after the date of execution of the indenture, liens existing or placed thereon at the time of the acquisition thereof, provided that the liens do not extend to any other mortgaged property;

liens for taxes, assessments and other governmental charges or requirements which are not delinquent or which are being contested in good faith by appropriate proceedings;

mechanics , workmen s, repairmen s, materialmen s, warehousemen s and carriers liens, other liens incident to construction, liens or privileges of any of our employees for salary or wages earned, but not yet payable, and other liens, including, without limitation, liens for workers compensation awards, arising in the ordinary course of business for charges or requirements which are not delinquent or which are being contested in good faith and by appropriate proceedings;

liens in respect of attachments, judgments or awards arising out of judicial or administrative proceedings (i) in an amount not exceeding the greater of (A) $10 million to the extent in existence in calendar year 2004; provided, that, with respect to measurement of these liens in existence in any subsequent calendar year, the amount shall be increased by the percentage increase in the consumer price index for all urban consumers, U.S. City average, or urban CPI, for the period commencing on January 1, 2004 and ending on January 1 of the applicable calendar year and (B) three percent of the principal amount of the senior bonds then outstanding or (ii) with respect to which we shall (x) in good faith be prosecuting an appeal or other proceeding for review and with respect to which we shall have secured a stay of execution pending the appeal or other proceeding or (y) have the right to prosecute an appeal or other proceeding for review;

easements, encumbrances, leases, reservations or other rights of others in, on, over and/or across, and laws, regulations and restrictions affecting, and defects, irregularities, exceptions and limitations in title to, the mortgaged property or any part thereof; provided, however, that the easements, encumbrances, leases, reservations, rights, laws, regulations, restrictions, defects, irregularities, exceptions and limitations do not, in our opinion, materially impair the use by us of the mortgaged property considered as a whole for the purposes for which it is held by us;

conservation easements in accordance with our plan of reorganization;

defects, irregularities, exceptions and limitations in title to real property subject to rights-of-way or other similar rights in favor of us or used or to be used by us primarily for right-of-way purposes or real property held under lease, easement, license or similar right; provided, however, that (i) we obtain from the apparent owner or owners of the real property a sufficient right, by the terms of the instrument granting the right-of-way, lease, easement, license or similar right, to the use thereof for the purposes for which we acquired it, (ii) we have power under eminent domain or similar statutes to remove the defects, irregularities, exceptions or limitations or (iii) the defects, irregularities, exceptions and limitations may be otherwise remedied without undue effort or expense; and defects, irregularities, exceptions and limitations in title to flood lands, flooding rights and/or water rights;

liens securing indebtedness or other obligations neither created, assumed nor guaranteed by us nor on account of which we customarily pay interest upon real property or rights in or relating to real property for the purpose of the distribution of electricity or gas, for the purpose of telephonic, telegraphic, radio, wireless or other electronic communication or otherwise for the purpose of obtaining rights-of-way;

leases existing at the date of execution of the indenture affecting mortgaged property owned by us at that time, and renewals and extensions thereof; and leases affecting that mortgaged property entered into after the date of execution of the indenture, or affecting mortgaged properties acquired by us after that date which, in either case, (i) have terms of not more than 10 years (including extensions or renewals at the option of the tenant) or (ii) do not materially impair the use by us of the properties for the purposes for which they are held by us;

liens vested in lessors, licensors, franchisors or permittors for rent or other amounts to become due or for other obligations or acts to be performed, the payment of which rent or other amounts or the performance of which other obligations or acts is required under leases, subleases, licenses, franchises or permits, so long as the payment of the rent or other amounts or the performance of the other obligations or acts is not delinquent or is being contested in good faith and by appropriate proceedings;

controls, restrictions, obligations, duties and/or other burdens imposed by federal, state, municipal or other law, or by rules, regulations or orders of governmental authorities, upon the mortgaged property or any part thereof or the operation or use thereof or upon us with respect to the mortgaged property or any part thereof or the operation or use thereof or with respect to any franchise, grant, license, permit or public purpose requirement, or any rights reserved to or otherwise vested in governmental authorities to impose any such controls, restrictions, obligations, duties and/or other burdens;

rights which governmental authorities may have by virtue of franchises, grants, licenses, permits or contracts, or by virtue of law, to purchase, recapture or designate a purchaser of or order the sale of the mortgaged property or any part thereof, to terminate franchises, grants, licenses, permits, contracts or other rights or to regulate our property and business; and any and all our obligations correlative to any of these rights;

liens required by law or governmental regulations (i) as a condition to the transaction of any business or the exercise of any privilege or license, (ii) to enable us to maintain self-insurance or to participate in any funds established to cover any insurance risks, (iii) in connection with workers compensation, unemployment insurance, social security or any pension or welfare benefit plan or (iv) to share in the privileges or benefits required for companies participating in one or more of the arrangements described in clauses (ii) and (iii) above;

liens on the mortgaged property or any part thereof which are granted by us to secure duties or public or statutory obligations or to secure, or serve in lieu of, surety, stay or appeal bonds;

rights reserved to or vested in others to take or receive any part of any coal, ore, gas, oil and other minerals, any timber and/or any electric capacity or energy, gas, water, steam and any other products, developed, produced, manufactured, generated, purchased or otherwise acquired by us or by others on our property;

rights and interests of persons other than us arising out of contracts, agreements and other instruments to which we are a party and which relate to the common ownership or joint use of property and all liens on the interests of persons other than us in property owned in common by those persons and us if and to the extent that the enforcement of those liens would not adversely affect our interests in that property in any material respect;

any restrictions on assignment and/or requirements of any assignee to qualify as a permitted assignee and/or a public utility or public service corporation;

any liens which have been bonded for the full amount in dispute or for the payment of which other adequate security arrangements have been made;

easements, ground leases or right-of-way in, upon, over and/or across our property or rights-of-way in our favor for the purpose of roads, pipelines, transmission lines, distribution lines, communication lines, railways, removal of coal or other minerals or timber, and other like purposes, or for the joint or common use of real property, rights-of-way, facilities and/or equipment; provided, however, that the grant does not materially impair the use of the property or rights-of-way for the purposes for which the property or rights-of-way are held by us;

prepaid liens and purchase money liens, as more particularly described in the indenture;

liens contemplated by our plan of reorganization;

the lien of our first and refunding mortgage prior to the effective date of our plan of reorganization;

any other liens which are in existence on the date of execution of the indenture and do not exceed $20 million;

any other liens which do not, in the aggregate, exceed $50 million to the extent in existence in calendar year 2004, provided that with respect to any of these liens in existence in any subsequent calendar year, the amount shall be increased by the percentage increase in the CPI for the period commencing on January 1, 2004 and ending on January 1 of the applicable calendar year; and

the lien under the indenture in favor of the trustee with respect to the compensation and other amounts payable by us to the trustee in its capacity as trustee.

Issuance of Additional Senior Bonds Prior to the Release Date

Prior to the release date, we may issue senior bonds of any series from time to time against property additions, retired securities and cash deposited with the trustee, in an aggregate principal amount not exceeding:

66 2/3% of the aggregate of the net amounts of property additions which constitute unfunded property (mortgaged property which has not previously been used as the basis for the issuance of senior bonds (not otherwise retired) or as the basis for the release or substitution of mortgaged property);

the aggregate principal amount of previously issued senior bonds that have been canceled or that we have delivered to the trustee for cancellation or previously issued senior bonds deemed to have been paid under the indenture, each of which we refer to as retired securities; and

the amount of cash deposited with the trustee.

Property additions generally include any item, unit or element of property which is owned by us and is subject to the lien of the indenture except (with certain exceptions) goodwill, going concern value rights or intangible property, or any property the cost of acquisition or construction of which is properly chargeable to one of our operating expense accounts at the time of such acquisition or construction.

The indenture includes limitations on the issuance of senior bonds against property subject to liens and upon the increase of the amount of any senior liens on funded property.

Funded property generally means mortgaged property which has been used as the basis for the issuance of senior bonds or as the basis for the release or substitution of mortgaged property under the indenture.

Retired securities means, generally, senior bonds which are no longer outstanding under the indenture, which have not been retired by the application of funded cash and which have not been used as the basis for the authentication and delivery of senior bonds, the release of property or the withdrawal of cash.

Prior to the release date, we also must deliver a net earnings certificate showing that our net income for 12 consecutive calendar months within the 18 calendar months immediately before the first day of the month in which we request authentication and delivery of the senior bonds has been not less than two times our annual interest requirements.

Net income means:

our operating revenues (which may include our revenues subject to possible refund at a future date);

less

our expenses, excluding (i) expenses for taxes paid or accrued on income or profits and other taxes measured by, or dependent on, net income, (ii) provisions for reserves for renewals, replacements, depreciation, amortization, depletion or retirement of property (or any expenditures therefor), (iii) expenses or provisions for interest on any of our indebtedness (including interest on capital lease obligations), for the amortization of debt discount, premium, expense or loss on reacquired debt, for amortization of payments made on swap agreements for any maintenance and replacement, improvement or sinking fund or other device for the retirement of any indebtedness, or for other amortization, (iv) expenses, losses or provisions for any non-recurring or extraordinary charge to income or to retained earnings of whatever kind or nature (including, without limitation, the recognition of expense or impairment due to the non-recoverability of assets or expense, charges for changes in accounting principles recorded in accordance with GAAP and non-cash writedowns, book losses or other charges), or non-recurring charges, whether or not recorded as a non-recurring or extraordinary charge in our books of account, and (v) provisions for any refund of revenues previously collected or accrued by us subject to possible refund;

plus

our other income, net of related expenses (excluding non-recurring charges, whether or not recorded as non-recurring or extraordinary charges in our books of account), including, but not limited to, non-utility operating income, cash distributions of our subsidiaries, any allowance for funds used during construction, and including any portion of the allowance, or of any analogous amounts, not included in other items (or any analogous item) in our books of account, other deferred costs (or any analogous amounts) in our books of account and any amounts collected by others to be applied to debt service on our indebtedness, and not otherwise treated on our books as revenue.

Annual interest requirements means the interest requirements for one year, at the respective stated interest rates, if any, borne prior to maturity, upon:

all senior bonds then outstanding under the indenture at the date of the certificate (excluding any senior bonds that will be paid or redeemed through senior bonds described in the next bullet point); provided, however, that, if outstanding senior bonds bear interest at a variable rate or rates, then the interest requirement on the senior bonds of affected series or tranches will be determined by reference to the rate or rates in effect two business days before the date of the certificate;

the senior bonds for which the net earnings certificate is then being delivered (and any other pending issuance); provided, however, that if senior bonds of any series or tranche are to bear interest at a variable rate or rates, then the interest requirement of that series or tranche will be determined by reference to the rate or rates to be in effect at the time of the initial authentication and delivery; and provided, further, that the determination of the interest requirement on senior bonds of a series subject to a periodic offering will be further subject to the other provisions described in the indenture; and

the principal amount of all other indebtedness secured by a senior lien upon the mortgaged property or any part thereof (except (i) our indebtedness the repayment of which supports or is supported by other indebtedness included in annual interest requirements described in one of the two bullet points above and (ii) indebtedness outstanding on the date of the net earnings certificate secured by a prepaid lien (as defined in the indenture) upon mortgaged property outstanding on that date and secured by a lien on a parity with or prior to the lien of the indenture upon mortgaged property), if we have issued, assumed or guaranteed the indebtedness or if we customarily pay the interest upon the principal thereof; provided, however, that if the indebtedness bears interest at a variable rate or rates, then the interest requirement will be determined by reference to the rate or rates in effect two business days immediately before the date of the certificate;

If when we make any net earnings certificate, any of our property (i) has been acquired during or after any period for which our net income is computed, (ii) has not been acquired in exchange or substitution for property the net earnings of which have been included in our net income and (iii) had been operated as a separate unit and items of revenue and expense attributable thereto are readily ascertainable by us, then the net earnings of that property (computed in the manner consistent with the computation of our net income) during that period or part of that period before its acquisition, to the extent that the same have not otherwise been included in our net income, will be included.

Release of Mortgaged Property

We may release property from the lien of the indenture if we deliver to the trustee cash equal to the funded property basis of the property to be released, less any taxes and expenses incidental to any sale, exchange, dedication or other disposition of the property to be released. Any of the following or any combination of the following will be applied as a credit against the cash we will be required to deliver to the trustee:

- the aggregate principal amount of obligations secured by a purchase money lien on the property to be released, subject to certain limitations described below;

- an amount equal to the net cost or net fair value to us (whichever is less) of certified property additions constituting unfunded property after certain deductions and additions, primarily including adjustments to offset property retirements (except that the adjustments need not be made if the property additions were acquired, made or constructed within 90 days before our request for release);

- an amount equal to 150% of the aggregate principal amount of senior bonds we would be entitled to issue on the basis of retired senior bonds (with that entitlement being waived by operation of such release); and

- an amount equal to 150% of the aggregate principal amount of senior bonds delivered to the trustee.

Funded property basis generally means the net cost of funded property or the net fair value to us of the funded property at the time it became funded property, whichever is less.

Net cost means, as of the date of calculation, the cost of the property, less the lesser of (i) the outstanding principal amount of any senior lien obligations as of the date of calculation or (ii) the cost of the property.

Net fair value means, as of the date of calculation, the fair value of the property, less the lesser of (i) the outstanding principal amount of any senior lien obligations as of the date of calculation or (ii) the fair value of the property.

Purchase money lien means, generally, a lien on the property being released which is retained by the transferor of such property to secure all or part of its purchase price or granted to one or more other persons in connection with the transfer or release thereof, or granted to or held by a trustee or agent for any such persons, and may include liens which cover property in addition to the property being released and/or which secure additional indebtedness.

We will be permitted to release from the lien of the indenture unfunded property (mortgaged property that has not been used as the basis for the issuance of senior bonds or as the basis for the release or substitution of mortgaged property under the indenture) without depositing any cash with the trustee or providing any other credits if either (i) the lower of the net cost or net fair value to us of all unfunded property (excluding the property to be released), after making certain adjustments, is at least zero, or (ii) the lower of the net cost or net fair value to us of the unfunded property to be released, after making certain adjustments, does not exceed the lower of the net cost or net fair value of all property acquired, made or constructed on or after 90 days before our request, after making certain adjustments. If neither (i) or (ii) in the immediately preceding sentence applies, we will be required to deliver a make-up amount in cash. We may apply as a credit against the cash we will be required to deliver to the trustee any of the items described under the bullet points in this section.

We also will be permitted to release in a calendar year property up to the lesser of $10 million (increased yearly by the urban CPI) or 3% of the aggregate principal amount of senior bonds then outstanding without complying with the other release provisions in the indenture. However, if, upon reliance on this release provision, we release funded property, we are required to deposit with the trustee, by the end of the calendar year, cash equal to 66 2/3% of the funded property basis of the property released, net of certain credits.

The indenture provides simplified procedures for the release of property taken by eminent domain, and provides for dispositions of certain obsolete property and grants or surrender of certain rights without any release or consent by the trustee.

The provisions described above permitting the release of property (except property taken by eminent domain) will be operable only if no event of default has occurred and is continuing under the indenture.

Withdrawal of Cash

Unless an event of default has occurred and is continuing and subject to certain limitations, cash held by the trustee may, generally,

- be withdrawn by us (i) to the extent of an amount equal to the net cost or net fair value to us (whichever is less) of property additions constituting unfunded property, after certain deductions and additions, primarily including adjustments to offset retirements (except that these adjustments need not be made if the property additions were acquired or made within 90 days before our request for withdrawal) or (ii) in an amount equal to 150% of the aggregate principal amount of senior bonds that we would be entitled to issue on the basis of retired senior bonds (with the entitlement to that issuance being waived by operation of the withdrawal) or (iii) in an amount equal to 150% of the aggregate principal amount of any outstanding senior bonds delivered to the trustee; or

- upon our request, applied to (i) the purchase of senior bonds or (ii) the payment (or provision for payment) at stated maturity of any senior bonds or the redemption (or provision for redemption) of any senior bonds which are redeemable.

Evidence to be Furnished to the Trustee Under the Indenture

We will demonstrate compliance with indenture provisions by providing written statements to the trustee from our officers or persons we select. For instance, we may select an engineer to provide a written statement regarding the value of property being certified or released or counsel regarding compliance with the indenture generally. In certain major matters, applicable law requires that an accountant, engineer or other expert must be independent. We must file a certificate each year with respect to our compliance with the conditions and covenants under the indenture.

Discharge of Lien; Release Date

Subject to the conditions described below, we may, without the consent of the holders of the senior bonds, eliminate all terms and conditions relating to collateral for the senior bonds, with the result that our obligations under the indenture and senior bonds would be entirely unsecured. We refer to the date on which the elimination of collateral occurs as the release date. The release date will be a date chosen by us and specified in an order signed by us and delivered to the trustee, which date shall not be earlier than the date of delivery by us to the trustee of each of the following:

- written evidence that the long-term ratings on our unsecured debt obligations, immediately after the release date, shall be at least equal to the initial ratings assigned by Moody s and by S&P on the initial series of senior bonds issued under the indenture or, if either or both of these rating agencies do not then rate our long-term unsecured debt obligations, comparable ratings by any other nationally recognized rating agency or agencies selected by us;

- a certificate signed by one of our authorized officers stating that the aggregate principal amount of debt secured by a lien on any principal property that will be outstanding immediately after the release date (excluding permitted secured debt described under Restrictions on Liens and Sale and Leaseback Transactions below) will not exceed 5% of our net tangible assets (as defined below) as determined by us as of a month end not more than 90 days prior to the release date;

a company order requesting execution and delivery by the trustee of a supplemental indenture (which may amend and restate the indenture) and those instruments that we may deem necessary or desirable to discharge, cancel, terminate or satisfy the lien of the indenture;

a certificate signed by one of our authorized officers stating that, to the knowledge of the signer, no event of default under the indenture has occurred and is continuing; and

any other documents required by the Trust Indenture Act or by the terms of any then outstanding senior bonds.

Net tangible assets for this purpose means the total amount of our assets determined on a consolidated basis in accordance with GAAP as of a month end not more than 90 days prior to the date of the above-referenced officer s certificate, less (i) the sum of our consolidated current liabilities determined in accordance with GAAP and (ii) the amount of our consolidated assets classified as intangible assets determined in accordance with GAAP.

As promptly as practicable after the occurrence of the release date, we will give notice to all holders of senior bonds of the occurrence of the release date in the same manner as a notice of redemption and disseminate a press release through a public medium as is customary announcing that the lien of the indenture has been released as of the release date.

From and after the release date, the term mortgaged property wherever used in this prospectus shall mean principal property.

Restrictions on Liens and Sale and Leaseback Transactions

From and after the release date, we will not, nor will we permit any of our significant subsidiaries (as defined below) to (i) issue, incur, assume or permit to exist any debt (as defined below) secured by lien (as defined below) on any of our principal property (as defined below) or on any principal property of any of our significant subsidiaries (whether that principal property is owned as of the date of execution of the indenture or thereafter acquired), unless we provide that the senior bonds will be equally and ratably secured with the debt or (ii) incur or permit to exist any attributable debt (as defined below) in respect of any principal property, provided, however, that the foregoing restrictions will not apply to the following:

to the extent we or a significant subsidiary consolidate with, or merge with or into, another entity, liens on the property of the entity securing debt in existence on the date of the consolidation or merger, provided that the debt and liens were not created or incurred in anticipation of the consolidation or merger and that the liens or encumbrances do not extend to cover any of our or a significant subsidiary s principal property;

liens existing on property acquired after the date of execution of the indenture, as long as the lien was not created or incurred in anticipation thereof and does not extend to or cover any of our or a significant subsidiary s other principal property;

liens of any kind, including purchase money liens, conditional sales agreements or title retention agreements and similar agreements, upon any property acquired, constructed, developed or improved by us or a significant subsidiary (whether alone or in association with others) which do not exceed the cost or value of the property acquired, constructed, developed or improved and which are created prior to, at the time of, or within 12 months after the acquisition (or in the case of property constructed, developed or improved, within 12 months after the completion of the construction, development or improvement and commencement of full commercial operation of the property, whichever is later) to secure or provide for the payment of any part of the purchase price or cost thereof, provided that the liens shall not extend to any principal property other than the property so acquired, constructed, developed or improved;

liens in favor of the United States, any state or any foreign country or any department, agency or instrumentality or any political subdivision of the foregoing to secure payments pursuant to any contract or statute or to secure any indebtedness, incurred for the purpose of financing all or any part of the purchase price or cost of constructing or improving the property subject to the lien, including liens related to governmental obligations the interest on which is tax-exempt under Section 103 of the Code or any successor section of the Code;

liens in favor of us, one or more of our significant subsidiaries, one or more of our wholly owned subsidiaries or any of the foregoing combination; and

replacements, extensions or renewals (or successive replacements, extensions or renewals), in whole or in part, of any lien or of any agreement referred to in the bullet points above or replacements, extensions or renewals of the debt secured thereby (to the extent that the amount of the debt secured by the lien is not increased from the amount originally so secured, plus any premium, interest, fee or expenses payable in connection with any replacements, refundings, refinancings, remarketings, extensions or renewals); provided that replacement, extension or renewal is limited to all or a part of the same property (plus improvements thereon or additions or accessions thereto) that secured the lien replaced, extended or renewed.

Notwithstanding the restriction described above, we or a significant subsidiary may, from and after the release date, (i) issue, incur or assume debt secured by a lien not otherwise permitted under the immediately preceding six bullet points on any principal property owned at the date of execution of the indenture or thereafter without providing that the senior bonds be equally and ratably secured with that debt and (ii) incur or permit to exist attributable debt in respect of principal property, in each case, so long as the aggregate amount of that debt and attributable debt, together with the aggregate amount of all other debt then outstanding and all other attributable debt, does not exceed 10% of our net tangible assets, as determined by us as of a month end not more than 90 days prior to the closing or consummation of the proposed transaction.

For these purposes:

attributable debt in respect of a sale and leaseback transaction means, at the time of determination, the present value of the obligation of the lessee for net rental payments during the remaining term of the lease included in the sale and leaseback transaction, including any period for which the lease has been extended or may, at the option of the lessor, be extended. The present value shall be calculated using a discount rate equal to the rate of interest implicit in the transaction, determined in accordance with GAAP.

capital lease obligations means, at the time any determination is to be made, the amount of the liability in respect of a capital lease that would at that time be required to be capitalized on a balance sheet in accordance with GAAP.

debt means any debt of ours for money borrowed and guarantees by us of debt for money borrowed but in each case not including liabilities in respect of capital lease obligations or swap agreements.

debt of a significant subsidiary means any debt of such significant subsidiary for money borrowed and guarantees by the significant subsidiary of debt for money borrowed but in each case excluding liabilities in respect of capital lease obligations or swap agreements.

lien means any mortgage, deed of trust, pledge, security interest, encumbrance, easement, lease, reservation, restriction, servitude, charge or similar right and any other lien of any kind, including, without limitation, any conditional sale or other title retention agreement, any lease of a similar nature, and any defect, irregularity, exception or limitation in record title or, when the context so requires, any lien, claim or interest arising from anything described in this bullet point.

net tangible assets means the total amount of our assets determined on a consolidated basis in accordance with GAAP as of a month end not more than 90 days prior to the closing or consummation of the proposed transaction, less (i) the sum of our consolidated current liabilities determined in accordance with GAAP and (ii) the amount of our consolidated assets classified as intangible assets determined in accordance with GAAP.

principal property means any property of ours or any of our significant subsidiaries, as applicable, other than property that prior to the release date would have constituted excepted property and property that were it to belong to us would have constituted excepted property prior to the release date.

significant subsidiary has the meaning specified in Rule 1-02(w) of Regulation S-X under the Securities Act of 1933, as amended, or the Securities Act, provided that, significant subsidiary shall not include any corporation or other entity substantially all the assets of which are, or prior to the release date would have constituted, excepted property.

swap agreement means any agreement with respect to any swap, forward, future or derivative transaction or option or similar agreement involving, or settled by reference to, one or more rates, currencies, commodities, equity or debt instruments or securities, or economic, financial or pricing indices or measures of economic, financial or pricing risk or value or any similar transaction or any combination of these transactions.

Consolidation, Merger, Transfer of Mortgaged Property

We may not consolidate with or merge with or into any other person (as defined below) or convey, otherwise transfer or lease all or substantially all of our mortgaged property to any person unless:

the person formed by that consolidation or into which we are merged or the person which acquires by conveyance or other transfer, or which leases, all or substantially all of the mortgaged property is a corporation, partnership, limited liability company, association, company, joint stock company or business trust, organized and existing under the laws of the United States, or any state thereof or the District of Columbia;

that person executes and delivers to the trustee a supplemental indenture that in the case of a consolidation, merger, conveyance or other transfer, or in the case of a lease if the term thereof extends beyond the last stated maturity of the senior bonds then outstanding, contains an assumption by the successor person of the due and punctual payment of the principal of and premium, if any, and interest, if any, on all senior bonds then outstanding and the performance and observance of every covenant and conditions under the indenture to be performed or observed by us;

in the case of a consolidation merger, conveyance or other transfer prior to the release date, that person executes and delivers to the trustee a supplemental indenture that contains a grant, conveyance, transfer and mortgage by the successor person confirming the lien of the indenture on the mortgaged property and subjecting to the lien all property (other than excepted property) thereafter acquired by the successor person that shall constitute an improvement, extension or addition to the mortgaged property or renewal, replacement or substitution of or for any part thereof and, at the election of the successor person, subjecting to the lien of the indenture the other property, real, personal and mixed, then owned or thereafter acquired by the person as the person shall specify in its sole discretion;

in the case of a lease, the lease is made expressly subject to termination by us or by the trustee at any time during the continuance of an event of default and by the purchaser of the property so leased at any sale of the property under the indenture, whether under the power of sale conferred by the indenture or pursuant to judicial proceedings;

immediately after giving effect to the transaction and treating any indebtedness that becomes our obligation as a result of the transaction as having been incurred by us at the time of the transaction, no default or event of default shall have occurred and be continuing; and

we have delivered to the trustee an officer s certificate and an opinion of counsel, each stating that the merger, consolidation, conveyance, lease or transfer, as the case may be, fully complies with all provisions of the indenture; provided, however, that the delivery of the officer s certificate and opinion of counsel shall not be required with respect to any merger, consolidation, conveyance, transfer or lease between us and any of our wholly owned subsidiaries.

Notwithstanding the foregoing, we may merge or consolidate with or transfer all or substantially all of our assets to an affiliate that has no significant assets or liabilities and was formed solely for the purpose of changing our jurisdiction of organization or our form of organization or for the purpose of forming a holding company; provided that the amount of our indebtedness is not increased; and provided, further that the successor assumes all of our obligations under the indenture.

In the case of the conveyance or other transfer of all or substantially all of the mortgaged property to any other person as contemplated under the indenture, upon the satisfaction of all the conditions described above we (as we would exist without giving effect to the transaction) would be released and discharged from all obligations under the indenture and on the senior bonds then outstanding unless we elect to waive the release and discharge.

The meaning of the term substantially all has not been definitely established and is likely to be interpreted by reference to applicable state law if and at the time the issue arises and will depend on the facts and circumstances existing at the time.

For these purposes:

- person means any individual, corporation, limited liability partnership, joint venture, trust or unincorporated organization, or any other entity whether or not a legal entity, or any governmental authority.

Modification of the Indentures; Waiver

We and the trustee may, with the consent of the holders of not less than a majority in aggregate principal amount of the senior bonds of each affected series then outstanding under the indenture, considered as one class, modify or amend the indenture, including the provisions relating to the rights of the holders of senior bonds of that series. However, no modification or amendment may, without the consent of each holder of affected senior bonds:

- change the stated maturity of, the principal of, reduce the principal amount or any premium payable on, reduce the interest rate of, or change the method of calculating the interest rate with respect to that senior bond;
- reduce the amount of principal payable upon acceleration of the maturity of that senior bond;
- change the type of consideration (coin, currency or other property) used to pay the principal of, or interest or premium on that senior bond;
- impair the right to institute suit for the enforcement of any payment on, or with respect to, that senior bond;
- reduce the percentage in principal amount of outstanding senior bonds the consent of whose holders is required for modification or amendment of the indenture;
- reduce the percentage of principal amount of outstanding senior bonds necessary for waiver of compliance with certain provisions of the indenture or for waiver of certain defaults;
- modify the provisions with respect to modification and waiver, except as provided in the indenture;
- reduce the quorum or voting requirements applicable to holders of the senior bonds; or
- prior to the release date, permit the creation of any lien (not otherwise permitted by the indenture) ranking prior to the lien of the indenture, with respect to all or substantially all of the mortgaged property or, except as otherwise expressly permitted under the indenture, release the lien of the indenture, terminate the lien of the indenture on all or substantially all of the mortgaged property or deprive the holders of the senior bonds of the benefit of the lien of the indenture.

The holders of not less than a majority in aggregate principal amount of the senior bonds of each affected series then outstanding under the indenture, voting as a single class, may waive compliance by us with certain provisions of the indenture benefiting holders of senior bonds of that series or the applicable senior bonds. The holders of not less than a majority in aggregate principal amount of the senior bonds of any series outstanding under the indenture may, on behalf of the holders of all of the senior bonds of that series, waive any past default under the 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 senior bonds of that series and defaults in respect of a covenant or provision in the indenture which cannot be modified, amended or waived without the consent of each holder of affected senior bonds.

We and the trustee may, without the consent of any holder of senior bonds, amend the indenture and the senior bonds for certain reasons, including to:

add covenants or other provisions applicable to us and for the benefit of the holders of senior bonds or one or more specified series thereof;

cure ambiguities;

correct or amplify the description of the mortgaged property, or to subject to the lien of the indenture additional property (including property of persons other than us);

specify any additional permitted liens with respect to that additional property;

add, change or eliminate any provision of the indenture so long as the addition, change or elimination does not adversely affect the interest of holders of senior bonds of any series in any material respect;

change any place or places for payment or surrender of senior bonds and where notices and demands to us may be served; and

in connection with the occurrence of the release date, amend (including amending and restating) the indenture to eliminate any provisions related to liens (other than the provisions described above under Restrictions on Liens and Sale and Leaseback Transactions), the lien of the indenture or the mortgaged property.

In order to determine whether the holders of the requisite principal amount of the outstanding senior bonds have taken an action under the indenture as of a specified date:

the principal amount of a discount bond 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 that date; and

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

Events of Default

An event of default means any of the following events which shall occur and be continuing:

failure to pay interest on a senior bond 30 days after such interest becomes due and payable;

failure to pay the principal of, or premium, if any, on, a senior bond when due and payable;

failure to perform any other covenant or warranty applicable to us in the indenture continuing for 90 days after the trustee, or the holders of at least 33% in aggregate principal amount of the senior bonds then outstanding give us notice of the default and require us to remedy the default, unless the trustee, or the trustee and holders of a principal amount of senior bonds not less than the principal amount of senior bonds the holders of which gave that notice agree in writing to an extension of the period prior to its expiration;

certain events of bankruptcy, insolvency or reorganization; and

the occurrence of any event of default as defined in any mortgage, indenture or instrument under which there may be issued, or by which there may be secured or evidenced, any of our debt, whether the debt exists on the date of execution of the indenture, or shall thereafter be created, if the event of default: (i) is caused by a failure to pay principal after final maturity of the debt after the expiration of the grace period

provided in the debt (which we refer to as a payment default), or (ii) results in the acceleration of the debt prior to its express maturity, and in each case, the principal amount of any of that debt, together with the principal amount of any other debt under which there has been a payment default or the maturity of which has been so accelerated, aggregates $100 million or more, provided, however, that if prior to the release date, the event of default under that mortgage, indenture or instrument is cured or waived or the acceleration is rescinded or the debt is repaid, within a period of 20 days from the continuation of that event of default beyond the applicable grace period or the occurrence of the acceleration, as the case may be, the event of default described in this bullet point shall be automatically cured; provided, further, that with respect to any mortgage, indenture or instrument that exists on the date of execution of the indenture, this provision only applies to the extent that the obligations to pay amounts thereunder are enforceable after the effective date of our plan of reorganization.

The $100 million amount specified in the bullet point above shall be increased in any calendar year subsequent to 2004 by the same percentage increase in the urban CPI for the period commencing January 1, 2004 and ending on January 1 of the applicable calendar year.

If the trustee deems it to be in the interest of the holders of the senior bonds, it may withhold notice of default, except defaults in the payment of principal, premium or interest with respect to any senior bond.

If an event of default occurs, the trustee or the holders of a majority in aggregate principal amount prior to the release date, or 33% in aggregate principal amount on and after the release date, of the senior bonds outstanding, considered as one class, may declare all principal immediately due and payable, provided, however, that if an event of default occurs with respect to certain events of bankruptcy, insolvency or reorganization, then the senior bonds outstanding shall be due and payable immediately without further action by the trustee or holders. If the default has been cured and other specified conditions in the indenture have been satisfied before any mortgaged property has been sold and before a judgment or decree for payment has been obtained by the trustee as provided in the indenture, the event or events of default giving rise to the acceleration will be deemed to have been cured and the declaration of acceleration and its effect will be deemed to have been rescinded and annulled.

No holder of senior bonds will have any right to enforce any remedy under the indenture unless the holder has given the trustee written notice of the event of default, the holders of at least 33% of the senior bonds have requested the trustee in writing to institute proceedings with respect to the event of default in its own name as trustee under the indenture and have offered the trustee reasonable indemnity against costs, expenses and liabilities with respect to the request, the trustee has failed to institute any proceeding within 60 days after receiving the notice from holders, and no direction inconsistent with the written request has been given to the trustee during the 60-day period by holders of at least a majority in aggregate principal amount of senior bonds then outstanding.

The trustee is not required to risk its funds or to incur financial liability if there is a reasonable ground for believing that repayment to it or adequate indemnity against risk or liability is not reasonably assured.

If an event of default has occurred and is continuing, holders of a majority in principal amount of the senior bonds may establish the time, method and place of conducting any proceedings for any remedy available to the trustee, or exercising any trust or power conferred upon the trustee.

Discharge

Any senior bond, or any portion of the principal amount thereof, will be deemed to have been paid for purposes of the indenture, and, at our election, our entire indebtedness in respect of the senior bonds will be deemed to have been satisfied and discharged, if certain conditions are satisfied, including an irrevocable deposit with the trustee or any paying agent (other than us), in trust of:

money (including funded cash not otherwise applied pursuant to the indenture) in an amount which will be sufficient, or

- in the case of a deposit made prior to the maturity of the senior bonds or portions thereof, eligible obligations (as described below) which do not contain provisions permitting the redemption or other prepayment thereof at the option of the issuer thereof, the principal of and the interest on which when due, without any regard to reinvestment thereof, will provide monies which, together with the money, if any, deposited with or held by the trustee or the paying agent, will be sufficient, or

- a combination of either of the two items described in the two preceding bullet points which will be sufficient,

to pay when due the principal of and premium, if any, and interest, if any, due and to become due on the senior bonds or portions thereof.

For this purpose, eligible obligations include direct obligations of, or obligations unconditionally guaranteed by, the United States of America, entitled to the benefit of the full faith and credit thereof, and depositary receipts or other instruments with respect to the obligations or any specific interest or principal payments due in respect thereof.

Transfer and Exchange

Senior bonds of any series may be exchanged for other senior bonds of the same series of any authorized denominations and of a like aggregate principal amount and tenor. Subject to the terms of the indenture and the limitations applicable to global securities, senior bonds may be presented for exchange or registration of transfer at the office of the registrar without service charge (unless otherwise indicated in a prospectus supplement), upon payment of any taxes and other governmental charges. Such transfer or exchange will be effected upon the 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.

If we provide for any redemption of a series of senior bonds in a prospectus supplement, we will not be required to execute, register the transfer of or exchange any senior bond of that series for 15 days before a notice of redemption is mailed or register the transfer of or exchange any senior bond selected for redemption.

Global Securities

Senior bonds may be represented, in whole or in part, by one or more global securities, with an aggregate principal amount equal to that of the senior bonds they represent. We will register each global security in the name of a depositary or its nominee and deposit the global security with the depositary. Each global security will bear a legend regarding the restrictions on exchanges and registration of transfer and other matters provided for in a supplemental indenture to the indenture.

No global security may be exchanged for senior bonds 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;

- an event of default has occurred and is continuing with respect to the senior bonds represented by the global security; or

- any other circumstances exist that may be indicated in a prospectus supplement.

If specified in a prospectus supplement, we will register all senior bonds 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 senior bonds 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 senior bonds registered in their names;

- receive or be entitled to receive physical delivery of certificated senior bonds in exchange for a global security; and be considered to be the owners or holders of the global security or any senior bonds 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 senior bonds 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. Similarly, 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, the 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 Trustee

The trustee may resign at any time upon written notice to us but the trustee s resignation will not take effect until a successor trustee accepts appointment. The trustee may be removed at any time by written notice delivered to the trustee and us and signed by the holders of at least a majority in principal amount of the outstanding senior bonds. In addition, under certain circumstances, we may remove the trustee, or any holder who has been a bona fide holder of a senior bond for at least six months may seek a court order for the removal of the trustee and the appointment of a successor trustee. We must give notice of resignation and removal of the trustee or the appointment of a successor trustee to all holders of senior bonds as provided in the indenture.

Trustees, Paying Agents and Registrars for the Senior Bonds

BNY Western Trust Company will initially act as the trustee, paying agent and registrar under the indenture. We may change either the paying agent or registrar without prior notice to the holders of the senior bonds, 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 BNY Western Trust Company.

Governing Law

The indenture and the senior bonds will be governed by California law.

Certain Aspects of a Mortgage

The remedies available to the trustee as mortgagee under the indenture must be exercised in accordance with California law in addition to the requirements of the indenture. Prior to the release date, the indenture grants a lien on substantially all of our real property and certain tangible personal property related to our facilities.

The following summaries contain a general discussion of certain aspects of California law related to mortgages of real property by a public utility. The summaries are not complete or intended to encompass all of the relevant laws and regulations of the state of California. The summaries are qualified in their entirety by reference to applicable laws and regulations governing mortgages of real property by a public utility.

Foreclosure

A mortgage which contains a power of sale authorizes the mortgagee, which in the case of the senior bonds is the trustee, to conduct a nonjudicial foreclosure sale of our real property subject to the lien of the indenture. The indenture includes a requirement that certain notices of sale be published in connection with a nonjudicial foreclosure sale. California law may also require that certain notices of sale be recorded, published and posted.

Foreclosure of a mortgage may also be accomplished by judicial action. Generally, the action is initiated by the service of legal pleadings upon all parties having an interest of record in any of the real property subject to

113

the proceeding. Certain notices of sale must also be served, published, posted and mailed. If the lender s right to foreclose is contested, the legal proceedings necessary to resolve the issue may be time consuming.

In light of the extensive number of real properties subject to the lien of the indenture, complying with the service and notice requirements of nonjudicial foreclosure sales or judicial actions will be very difficult and time consuming.

It is uncommon for a third party to purchase the encumbered property at a foreclosure sale. Typically, the foreclosing party purchases the property with a credit bid in an amount less than or equal to the unpaid principal amount of the mortgage or deed of trust, accrued and unpaid interest and the expense of foreclosure. California law limits the amount of foreclosure costs and expenses, including attorneys fees, which may be recovered by a lender. Depending upon market conditions, the ultimate proceeds of a sale (whether sale proceeds received from a third party bidder or, more commonly, the value of the property itself) may be less than the amount owed by the borrower.

The sale or other disposition of all or a portion of our real property subject to the lien of the indenture in connection with a judicial or non-judicial foreclosure also could require approval or other action by applicable regulatory authorities, including the CPUC, the FERC and the NRC.

Rights of Redemption

After foreclosure of a mortgage by judicial action (but not by a nonjudicial foreclosure sale), the borrower or its successor in interest is given a statutory period (ranging from three months to one year) in which to redeem the real property from the foreclosure sale. Redemption may occur only upon payment of the following amounts: (i) the amount paid by the purchaser at the foreclosure sale; plus (ii) the costs paid by the purchaser for taxes, fire insurance, maintenance, upkeep, and repairs; plus (iii) any amounts paid by the purchaser on senior liens on the property to protect the purchaser s interest; plus (iv) interest on these amounts; plus (v) if the purchaser was a junior lien holder prior to the sale, any amounts that were secured by its junior lien on the property; less (vi) any rents profits and value of occupancy received by the purchaser from the property. The effect of a statutory right of redemption is to diminish the ability of the foreclosing party or parties to sell the real property collateral following the foreclosure sale. The rights of redemption would defeat the title of any purchaser after foreclosure or sale under a mortgage. Consequently, the practical effect of the redemption right is to force the foreclosing party or parties to maintain the real property and pay the expenses of ownership until the redemption period has expired.

One-Action Rule and Limitation on Deficiency Judgments

There are statutory prohibitions in California that limit the remedies of a lender under a mortgage. The only judicial action available for the recovery of any debt or the enforcement of any right secured by mortgage upon real property is an action for judicial foreclosure, known as the one-action rule. As a result, no judicial action may be commenced to recover a separate judgment against the borrower for the amount of indebtedness secured by a mortgage. If an action on the debt is commenced in spite of this prohibition, that action must be dismissed upon the objection of the borrower, known as the defense aspect of the rule. If, on the other hand, an action is commenced, the borrower does not object and a judgment is rendered in that action, then the lender will lose any security interest in the property encumbered by its mortgage. In addition, even if a judicial foreclosure action is properly commenced, if only a portion of the lender s collateral is included in that action, the lender can be compelled by the borrower to include all its collateral in that action, and if the action goes to judgment without all the collateral being foreclosed upon, the lender will lose its security interest in any omitted collateral, known as the security-first aspect of the rule. Several California cases have held that certain actions taken by lenders short of filing a court action, such as the assertion of a banker s setoff, either are actions for purposes of the one-action rule or violate the security-first aspect of the rule, in either case resulting in the lender losing the security interest that was provided by its mortgage.

In addition to the one-action rule, there are statutes that limit the deficiency judgment a lender to a public utility may obtain against the borrower after judicial or nonjudicial foreclosure. A deficiency judgment is a judgment against the borrower equal to the difference between the amount due to the lender for the indebtedness and other costs and expenses, and the amount paid for the property at the foreclosure sale, whether by the lender s credit bid or a third party s cash bid. The borrower is entitled to have credited against the indebtedness, the fair value of the property sold at foreclosure if this value is greater than the amount for which the property was actually sold. The purpose of these statutes is generally to prevent a lender from obtaining a large deficiency judgment against the borrower as a result of low or no bids at the foreclosure sale.

California law permits a public utility to waive the protections afforded by the one-action rule (including the security first aspect). We have affirmatively waived these rights in the indenture. While we believe that this waiver is enforceable, to our knowledge, there has been no reported decision of a California court addressing the enforceability of such a waiver.

Bankruptcy

Should we go back into bankruptcy after the effective date of our plan of reorganization, there could be adverse effects on the senior bonds that could result in delays or reductions in payments to the holders of the senior bonds. For example, the automatic stay provisions of the Bankruptcy Code could prevent (unless approval of the bankruptcy court was obtained) any action to collect any amount we owe on the senior bonds or under the indenture or any action to enforce our obligations under the senior bonds or the indenture. In particular, the trustee may be prevented from foreclosing on any collateral that secures the senior bonds. These restrictions may also prevent the trustee from making payments to the holders of the senior bonds from funds in the trustee s possession during the pendency of the bankruptcy proceedings. In addition, we may be able to cause any of our property that is subject to the lien of the indenture to be released to us, free and clear of that lien, and we may use that property, as long as the bankruptcy court determines that the rights of the trustee and the holders of the senior bonds will be adequately protected. We also may be able to borrow money secured by a lien on the trust estate that is senior to the lien of the indenture, as long as the bankruptcy court determines that the rights of the trustee and the holders of the senior bonds will be adequately protected. We may be able, without the consent and over the objection of the trustee and the holders of the senior bonds, to alter the priority, interest rate, payment terms, collateral, maturity dates, payment sources, covenants, and other terms or provisions of the indenture and the senior bonds, as long as the bankruptcy court determines that the alterations are fair and equitable. Further, the trustee may be required to return to us any property that became subject to the lien of the indenture within the 90 days immediately preceding the commencement of the bankruptcy proceedings. Payments previously made to the holders of the senior bonds during the 90 days immediately preceding the commencement of the bankruptcy proceedings may be avoided as preferential payments, so that the holders would be required to return these payments to us. The lien of the indenture may not attach to any property that we acquire after the commencement of the bankruptcy proceedings. There may be other possible effects of a bankruptcy that could result in delays or reduction in payments to the holders of the senior bonds.

Environmental

Real property pledged as security to a lender may be subject to unforeseen environmental risks. Most environmental statutes create obligations for any party that can be classified as the owner or operator of a facility (referring to both operating facilities and to real property). Under the laws of California and under CERCLA, a lender may be liable, as an owner or operator, for costs arising out of releases or threatened releases of hazardous substances that require remedy at a mortgaged property, if agents or employees of the lender have become sufficiently involved in the operations of the borrower or, subsequent to a foreclosure, in the management of the property. Such liability may arise regardless of whether the environmental damage or threat was caused by a prior owner.

Under federal and certain state laws, contamination of a property may give rise to a lien on the property to assure the payment of clean-up costs. These clean-up costs may be substantial. It is possible that such costs could become a liability of the lender and occasion a loss to the lender in certain circumstances if such remedial costs were incurred.

PLAN OF DISTRIBUTION

We may sell any series of senior bonds 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 senior bonds will state the terms of the offering of the senior bonds, including:

- the name or names of any underwriters or agents;
- the purchase price of the senior bonds 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 senior bonds may be listed.

If we use underwriters in the sale, the senior bonds 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.

Senior bonds 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 senior bonds together with the members of the underwriting syndicate, if any. Unless otherwise set forth in a prospectus supplement, the obligations of the underwriters to purchase the particular senior bonds will be subject to certain conditions precedent and the underwriters will be obligated to purchase all of the senior bonds being offered if any are purchased.

We may sell senior bonds directly or through agents we designate from time to time. The prospectus supplement will set forth the name of any agent involved in the offer or sale of senior bonds in respect of which such prospectus supplement is delivered and any commissions payable by us to such agent. Unless otherwise indicated in a 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 senior bonds may be deemed to be underwriters as defined in the Securities Act, and any discounts or commissions received by them on the sale or resale of senior bonds 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, senior bonds will not be listed on a national securities exchange. Any underwriters to whom senior bonds are sold by us for public offering and sale may make a market in the senior bonds, but such underwriters will not be obligated to do so and may discontinue any market making at any time without notice.

To facilitate a senior bonds offering, any underwriter may engage in over-allotment, short covering transactions and penalty bids or stabilizing transactions 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 senior bonds so long as the stabilizing bids do not exceed a specified maximum.

Short covering positions involve purchases of senior bonds 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 senior bonds originally sold by the dealer are purchase in a covering transaction to cover short positions.

These activities may cause the price of the senior bonds 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 senior bonds 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 senior bonds are described in the section of this prospectus titled Description of the Senior Secured Bonds. 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 proceeding. 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, 2003 and 2002, and for each of the three years in the period ended December 31, 2003, 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 2003 and 2001 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 senior bonds has been passed upon for us by Orrick, Herrington & Sutcliffe LLP. The validity of the senior bonds 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 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 senior bonds offered hereby:

- our annual report on Form 10-K for the year ended December 31, 2003; and

- our current reports on Form 8-K filed with the SEC on January 22, 2004, February 2, 2004, February 19, 2004 and March 2, 2004 (including specifically Exhibit 99, which supersedes Exhibit 13 to the Form 10-K for the year ended December 31, 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 indenture and the other documents which establish the terms of senior bonds 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

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, 2003 and 2002, and the related consolidated statements of operations, cash flows and shareholders equity for each of the three years in the period ended December 31, 2003. 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, 2003 and 2002, and the results of its consolidated operations and its cash flows for each of the three years in the period ended December 31, 2003, 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, during 2003, the Company adopted new accounting standards to account for asset retirement obligations and financial instruments with characteristics of both liabilities and equity. During 2001, the Company adopted new accounting standards related to derivatives and certain interpretations of the Derivatives Implementation Group of the Financial Accounting Standards Board.

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 18, 2004
(March 1, 2004 as to the last three paragraphs of Note 1)

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

CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions)

	Year Ended December 31,		
	2003	**2002**	**2001**
Operating Revenues			
Electric	$ 7,582	$ 8,178	$ 7,326
Natural gas	2,856	2,336	3,136
Total operating revenues	10,438	10,514	10,462
Operating Expenses			
Cost of electricity	2,319	1,482	2,774
Cost of natural gas	1,467	954	1,832
Operating and maintenance	2,935	2,817	2,385
Depreciation, amortization and decommissioning	1,218	1,193	896
Reorganization professional fees and expenses	160	155	97
Total operating expenses	8,099	6,601	7,984
Operating Income	2,339	3,913	2,478
Reorganization interest income	46	71	91
Interest income	7	3	32
Interest expense (non-contractual interest expense of $131 million in 2003, $149 million in 2002, and $164 million in 2001)	(953)	(988)	(974)
Other income (expense), net	13	(2)	(16)
Income Before Income Taxes	1,452	2,997	1,611
Income tax provision	528	1,178	596
Net Income Before Cumulative Effect of a Change in Accounting Principle	924	1,819	1,015
Cumulative effect of a change in accounting principle (net of income tax benefit of $1 million for the year ended December 31, 2003)	(1)		
Net Income	923	1,819	1,015
Preferred stock dividend requirement	22	25	25
Income Available for Common Stock	$ 901	$ 1,794	$ 990

See accompanying Notes to the Consolidated Financial Statements.

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

CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31, 2003	Balance at December 31, 2002
ASSETS		
Current Assets		
Cash and cash equivalents	$ 2,979	$ 3,343
Restricted cash	403	150
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $68 million in 2003 and $59 million in 2002)	2,424	1,921
Related parties	17	17
Regulatory balancing accounts	248	98
Inventories:		
Gas stored underground	166	154
Materials and supplies	126	121
Prepaid expenses and other	100	165
Total current assets	6,463	5,969
Property, Plant and Equipment		
Electric	20,468	18,922
Gas	8,355	8,123
Construction work in progress	379	427
Total property, plant and equipment	29,202	27,472
Accumulated depreciation	(11,100)	(10,494)
Net property, plant and equipment	18,102	16,978
Other Noncurrent Assets		
Regulatory assets	2,001	2,011
Nuclear decommissioning funds	1,478	1,335
Other	1,022	1,300
Total other noncurrent assets	4,501	4,646
TOTAL ASSETS	$ 29,066	$ 27,593

See accompanying Notes to the Consolidated Financial Statements.

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

CONSOLIDATED BALANCE SHEETS
(in millions, except per share amounts)

	Balance at December 31, 2003	Balance at December 31, 2002
LIABILITIES AND SHAREHOLDERS EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Long-term debt, classified as current	$ 310	$ 281
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	657	380
Related parties	224	130
Regulatory balancing accounts	186	364
Other	365	374
Interest payable	153	126
Deferred income taxes	86	
Other	637	625
Total current liabilities	2,908	2,570
Noncurrent Liabilities		
Long-term debt	2,431	2,739
Rate reduction bonds	870	1,160
Regulatory liabilities	3,979	3,082
Asset retirement obligations	1,218	
Decommissioning obligations		1,400
Deferred income taxes	1,334	1,485
Deferred tax credits	127	144
Preferred stock with mandatory redemption provisions	137	
Other	1,471	1,274
Total noncurrent liabilities	11,567	11,284
Liabilities Subject to Compromise		
Financing debt	5,603	5,605
Trade creditors	3,899	3,803
Total liabilities subject to compromise	9,502	9,408
Commitments and Contingencies (Notes 1, 2 and 11)		
Preferred Stock With Mandatory Redemption Provisions		
6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009		137
Shareholders Equity		
Preferred stock without mandatory redemption provisions		
Nonredeemable, 5% to 6%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 7.04%, outstanding 5,973,456 shares	149	149
Common stock, $5 par value, authorized 800,000,000 shares, issued 321,314,760 shares	1,606	1,606
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,964	1,964

Reinvested earnings	1,706	805
Accumulated other comprehensive loss	(6)	
Total shareholders equity	5,089	4,194
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY	$29,066	$27,593

See accompanying Notes to the Consolidated Financial Statements.

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2003	**2002**	**2001**
Cash Flows From Operating Activities			
Net income	$ 923	$ 1,819	$ 1,015
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and decommissioning	1,218	1,193	896
Deferred income taxes and tax credits, net	(75)	378	(306)
Reversal of ISO accrual		(970)	
Other deferred charges and noncurrent liabilities	581	102	(954)
Gain on sale of assets	(29)		
Cumulative effect of a change in accounting principle	1		
Net effect of changes in operating assets and liabilities:			
Restricted cash	(253)	(97)	(3)
Accounts receivable	(590)	212	105
Inventories	(17)	62	(57)
Accounts payable	507	198	1,312
Accrued taxes	48	(345)	1,415
Regulatory balancing accounts, net	(329)	(23)	311
Other working capital	29	11	711
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(87)	(1,442)	(16)
Other, net	43	36	336
Net cash provided by operating activities	1,970	1,134	4,765
Cash Flows From Investing Activities			
Capital expenditures	(1,698)	(1,546)	(1,343)
Net proceeds from sale of asset	49	11	
Other, net	(114)	26	5
Net cash used by investing activities	(1,763)	(1,509)	(1,338)
Cash Flows From Financing Activities			
Net repayments under credit facilities and short-term borrowings			(28)
Long-term debt matured, redeemed, or repurchased	(281)	(333)	(111)
Rate reduction bonds matured	(290)	(290)	(290)
Other, net			(1)
Net cash used by financing activities	(571)	(623)	(430)
Net change in cash and cash equivalents	(364)	(998)	2,997
Cash and cash equivalents at January 1	3,343	4,341	1,344
Cash and cash equivalents at December 31	$ 2,979	$ 3,343	$ 4,341
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	$ 39	$ 75	$ 87

Cash paid for:			
Interest (net of amounts capitalized)	773	1,105	361
Income taxes paid (refunded), net	648	1,186	(556)
Reorganization professional fees and expenses	99	99	19
Supplemental disclosures of noncash investing and financing activities			
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities	181	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)

	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 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 (net of income tax expense of $62 million)					90	90		90
Mark-to-market adjustments for hedging (net of income tax benefit of $3 million)					(5)	(5)		(5)
Net reclassification to earnings (net of income tax benefit of $58 million)					(85)	(85)		(85)
Foreign currency translation adjustments (net of income tax benefit of $1 million)					(2)	(2)		(2)
Comprehensive income								$ 1,013
Preferred stock dividend requirement				(25)		(25)		
Balance December 31, 2001	1,606	1,964	(475)	(989)	(2)	2,104	294	
Net Income				1,819		1,819		$ 1,819
Foreign currency translation adjustments (net of income tax expense of $1 million)					2	2		2
Comprehensive income								$ 1,821
Preferred stock dividend requirement				(25)		(25)		
Balance December 31, 2002	1,606	1,964	(475)	805		3,900	294	
Net Income				923		923		$ 923
Retirement plan remeasurement (net of income tax benefit of $2 million)					(3)	(3)		(3)
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax benefit of $2 million)					(3)	(3)		(3)
Comprehensive income								$ 917
Preferred stock dividend requirement				(22)		(22)		

Balance December 31, 2003	$ 1,606	$ 1,964	$ (475)	$ 1,706	$ (6)	$ 4,795	$ 294

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: GENERAL

Organization and Basis of Presentation

Pacific Gas and Electric Company, or the Utility, is a public utility operating in northern and central California. The Utility engages primarily in the businesses of electricity and natural gas distribution, electricity generation, electricity transmission, and natural gas transportation and storage. The Utility is a wholly owned subsidiary of PG&E Corporation. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation. The Utility served approximately 4.9 million electricity distribution customers and approximately 3.9 million natural gas distribution customers at December 31, 2003. The Utility is headquartered in San Francisco, California.

As discussed further in Note 2, on April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code, or Bankruptcy Code, in the United States, or U.S. Bankruptcy Court for the Northern District of California. The Utility retained control of its assets and is authorized to operate its business as a debtor-in-possession during its Chapter 11 proceeding.

The Utility s Consolidated Financial Statements include its accounts and those of its wholly owned and controlled subsidiaries. All significant intercompany transactions have been eliminated from the Consolidated Financial Statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America, or GAAP requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of revenues, expenses, assets and liabilities and the disclosure of contingencies. 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.

The Utility s Consolidated Financial Statements have been prepared in accordance with the American Institute of Certified Public Accountants Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code, or SOP 90-7, 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 the Utility s Chapter 11 filing, the realization of assets and liquidation of liabilities are subject to uncertainty. Under SOP 90-7, certain claims against the Utility existing before the Utility s Chapter 11 filing are classified as liabilities subject to compromise on the Utility s Consolidated Balance Sheets. Additionally, professional fees and expenses directly related to the Utility s Chapter 11 proceeding and interest income on funds accumulated during the Chapter 11 proceedings are reported separately as reorganization items. Finally, the extent to which the Utility s reported interest expense differs from its stated contractual interest is disclosed on the Utility s Consolidated Statements of Operations.

Summary of Significant Accounting Policies

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

Adoption of New Accounting Policies

Consolidation of Variable Interest Entities

In December 2003, the Financial Accounting Standards Board, or the FASB, issued Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities, or FIN 46R, replacing Interpretation No. 46, Consolidation of Variable Interest Entities, or FIN 46, which was issued in January 2003. FIN 46R was issued to replace FIN 46, and to clarify the required accounting for interests in variable interest entities. A variable interest entity is an entity that does not have sufficient equity investment at risk, or the holders of the equity instruments lack the essential characteristics of a controlling financial interest. A variable interest entity is 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 is entitled to receive a majority of the entity s residual returns, or both.

The Utility must apply the provisions of FIN 46R as of January 1, 2004. The Utility is continuing to evaluate the impacts of FIN 46R s initial recognition, measurement and disclosure provisions on its Consolidated Financial Statements and is unable to estimate the impact, if any, which will result when FIN 46R becomes effective. The Utility has investments in unconsolidated affiliates, which are mainly engaged in the purchase of low-income residential real estate property. It is reasonably possible that the Utility will be required to consolidate its interests in these entities as a result of the adoption of FIN 46R. At December 31, 2003, the Utility s recorded investment in these entities was approximately $21 million. As a limited partner, the Utility s exposure to potential loss is limited to its investment in each partnership.

Reporting Realized Gains and Losses on Derivative Instruments Held for Non-Trading Purposes

On October 1, 2003, the Utility adopted the Emerging Issues Task Force, or EITF, Issue No. 03-11, Reporting Realized Gains and Losses on Derivative Instruments Not Held for Trading Purposes That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes as Defined in EITF Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities. Under EITF Issue No. 03-11, the determination of whether realized gains and losses on derivative instruments held for non-trading purposes should be reported on a net or gross basis is a matter of judgment that depends on the relevant facts and circumstances and the economic substance of the transaction.

For all non-trading derivative instruments that do not qualify for cash flow hedge accounting treatment, the Utility reports both realized and unrealized gains and losses on a net basis in the Consolidated Statement of Operations. The financial reporting requirements reflected in EITF Issue No. 03-11 did not have any impact on the Consolidated Financial Statements of the Utility, nor did they result in any reclassifications of revenues and expenses.

Amendment of Statement 133 on Derivative Instruments and Hedging Activities

On July 1, 2003, the Utility adopted Statement of Financial Accounting Standard, or 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 the criteria for qualifying for the normal purchases and sales exception, certain derivative instruments embedded in other contracts and for hedging activities. SFAS No. 149 also clarifies circumstances under which a contract with an initial net investment meets the characteristics of a derivative instrument according to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, or SFAS No. 133. 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 continue to be applied in accordance with their respective effective dates.

The requirements of SFAS No. 149 are effective for derivative instruments entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The adoption of SFAS No. 149 did not have a material impact on the Consolidated Financial Statements of the Utility.

Accounting for Financial Instruments with Characteristics of Both Liabilities and Equity

In May 2003, the FASB issued Statement No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity, or SFAS No. 150. SFAS No. 150 addresses concerns of how to measure and classify in the balance sheet 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 Utility adopted the requirements of SFAS No. 150 in the third quarter of 2003. As a result, the Utility reclassified approximately $137 million of preferred stock with mandatory redemption provisions as a noncurrent liability. The reclassification did not have an impact on earnings of the Utility. Upon adopting SFAS No. 150, all amounts paid or to be paid to the holders of preferred stock with mandatory redemption provisions in excess of the initial measured amount are reflected in interest expense. Dividends paid or accrued in prior periods have not been reclassified.

Determining Whether an Arrangement Contains a Lease

In May 2003, the EITF reached consensus on EITF Issue No. 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 the 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. The adoption of EITF 01-8 did not have a material impact on the Consolidated Financial Statements of the Utility.

Accounting for Asset Retirement Obligations

On January 1, 2003, the Utility adopted SFAS No. 143, Accounting for Asset Retirement Obligations, or 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 No. 143 and costs recovered through the ratemaking process.

The impacts of adopting SFAS No. 143 were as follows:

The Utility 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 December 31, 2003. Through December 31, 2002, the Utility had recorded approximately $1.4 billion for its nuclear and fossil decommissioning obligations. Prior to adoption of SFAS No. 143, these nuclear and fossil decommissioning obligations have been recorded in accumulated depreciation. However, as a result of recent guidance from the staff of the Securities and Exchange Commission, or SEC, the Utility reclassified these obligations as separate noncurrent liabilities in its December 31, 2002 Consolidated Balance Sheet;

Upon adoption of SFAS No. 143, the Utility 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, the Utility then reduced the asset retirement obligations by approximately $53 million. The Utility increased its property, plant and equipment balance by approximately $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, the Utility recorded a regulatory liability of approximately $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 the expense recognized for ratemaking purposes. The cumulative effect of the change in accounting principle for the Utility s fossil facilities as a result of adopting SFAS No. 143 was a loss of approximately $1 million, after-tax; and

In connection with an application filed with the CPUC requesting an increase in the Utility s nuclear decommissioning revenue requirements for the years 2003 through 2005, during 2003 the Utility developed a new estimate for costs to decommission its nuclear facilities.

As a result, the Utility reduced its asset retirement obligation by approximately $223 million from the amount recorded upon the Utility s adoption of SFAS No. 143 on January 1, 2003. The Utility also reduced its property, plant and equipment balance by approximately $61 million. Finally, to account for timing differences between recognition of the modified asset retirement obligation as recorded in accordance with GAAP and ratemaking purposes, the Utility increased its regulatory liability by approximately $162 million.

If SFAS No. 143 had been adopted on January 1, 2002, the pro forma effects on earnings of the accounting change for the year ended December 31, 2002 would not have been material. The amounts recorded upon adoption of SFAS No. 143 reflect the pro forma effects on the Consolidated Balance Sheets had SFAS No. 143 been adopted on December 31, 2002.

The Utility has established trust funds that are legally restricted for purposes of settling its nuclear decommissioning obligations. The fair value and carrying value of these trust funds was approximately $1.4 billion at December 31, 2003 and approximately $1.3 billion at December 31, 2002.

The Utility may have potential asset retirement obligations under various land right documents associated with its transmission and distribution facilities. The majority of the Utility s land rights are perpetual. Any non-perpetual land rights generally are renewed continuously because the Utility 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.

The Utility collects estimated removal costs in rates through depreciation in accordance with regulatory treatment. These amounts do not represent SFAS No. 143 asset retirement obligations. Historically, these removal costs have been recorded in accumulated depreciation. However, as a result of recent guidance from the staff of the SEC the Utility reclassified this obligation to a regulatory liability in its December 31, 2003 and 2002 balance sheets. The Utility s estimated removal costs recorded as a regulatory liability were approximately $1.8 billion at December 31, 2003 and approximately $1.6 billion at December 31, 2002.

Accounting for Goodwill and Other Intangible Assets

The Utility had no goodwill on their Consolidated Balance Sheets at December 31, 2003 or 2002. Other intangible assets consist mainly of hydroelectric facility licenses and other agreements. The gross carrying amount of the hydroelectric facility licenses and other agreements was approximately $73 million at December 31, 2003 and $67 million at December 31, 2002. The accumulated amortization was approximately $19 million at December 31, 2003 and $16 million at December 31, 2002.

The Utility s amortization expense related to intangible assets was approximately $3 million in 2003, $3 million in 2002 and $2 million in 2001. The estimated annual amortization expense for the Utility s intangible assets for 2004 through 2008 is approximately $3 million.

Significant Accounting Policies

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. The Utility primarily invests its cash in money market funds and in short-term obligations of the U.S. government and its agencies.

The Utility had account balances with Fiduciary Trust Company International that were greater than 10% of PG&E Corporation s and the Utility s total cash and cash equivalents balance at December 31, 2003.

Restricted Cash

Restricted cash includes deposits under certain third party agreements, amounts held in escrow as collateral required by the California Independent System Operator, or ISO, and other counterparties and deposits securing workers compensation obligations.

Inventories

Inventories include materials, supplies and gas stored underground that are valued at average cost.

Income Taxes

The Utility 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, mainly synthetic fuel tax credits, are recognized in income as earned.

The Utility is included in PG&E Corporation s consolidated U.S. (federal) income tax return. In addition, the Utility is included in state income tax returns of PG&E Corporation for those states in which PG&E Corporation files combined state income tax returns. PG&E Corporation and the Utility are parties to a tax-sharing arrangement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

Investments in Affiliates

The Utility has investments in unconsolidated affiliates, which are mainly engaged in the purchase of low-income residential real estate property. The equity method of accounting is applied to the Utility s investment in these entities. Under the equity method, the Utility s share of equity income or losses of these entities is reflected as equity in earnings of affiliates. As of December 31, 2003, the Utility s recorded investment in these entities totaled approximately $21 million in accordance with the equity method of accounting. As a limited partner, the Utility s exposure to potential loss is limited to its investment in each partnership.

Related Party Agreements and Transactions

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. These services are priced either at the fully loaded cost (*i.e.*, direct costs and allocations of overhead costs) or at the higher of fully loaded cost or fair market value, depending on the nature of the services. PG&E Corporation also allocates certain other corporate administrative and general costs to the Utility and other subsidiaries using agreed allocation factors, including the number of employees, operating expenses excluding fuel purchases, total assets and other cost allocation methodologies. The Utility purchases natural gas transportation services from Gas Transmission Northwest Corporation, or GTNW, formerly known as PG&E Gas Transmission, Northwest Corporation. Effective April 1, 2003, the Utility no longer purchases natural gas from NEGT Energy Trading Holdings Corporation, or NEGT ET, formerly known as PG&E Energy Trading Holdings Corporation. Both GTNW and NEGT ET are subsidiaries of National Energy & Gas Transmission, Inc., or NEGT, formerly known as PG&E National Energy Group, or PG&E NEG, which was incorporated on December 18, 1996 as a wholly owned subsidiary of PG&E Corporation. The Utility sold natural gas transportation capacity and other ancillary services to NEGT ET until NEGT s Chapter 11 proceeding was imminent. These services were priced at either tariff rates or fair market value, depending on the nature of the services provided. Through July 7, 2003, all significant intercompany transactions are eliminated in consolidation; therefore, no profit or loss resulted from these transactions. Beginning July 8, 2003, the Utility s transactions with NEGT are no longer eliminated in consolidation. The Utility s significant related party transactions and related receivable (payable) balances were as follows:

(in millions)	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001	Receivable (Payable) Balance Outstanding at Year Ended December 31, 2003	Receivable (Payable) Balance Outstanding at Year Ended December 31, 2002
Revenues from:					
Administrative services provided to PG&E Corporation	$ 8	$ 7	$ 6	$	$ 1
Natural gas transportation capacity services provided to NEGT ET	8	9	11		
Contribution in aid of construction received from NEGT		2	5		3
Trade deposit due from GTNW	3		11	15	12
Other			1		
Expenses from:					
Administrative services received from PG&E Corporation	$ 183	$ 106	$ 127	$ (396)	$ (289)
Interest accrued on pre-petition liabilities due to PG&E Corporation	6	8	3	(2)	(2)
Administrative services received from NEGT	2	2		(1)	(2)
Software purchases from NEGT ET	1				
Natural gas commodity services received from NEGT ET	10	49	120		(26)
Natural gas transportation services received from GTNW	58	47	40	(8)	(8)
Trade deposit due to NEGT ET	(7)	7			(7)

Property, Plant and Equipment

Property, plant and equipment are reported at their original cost, unless impaired under the provisions of SFAS No. 144 Accounting for Impairment or Disposal of Long-Lived Assets, or SFAS No. 144. Original costs include:

- Labor and materials;
- Construction overhead; and
- Capitalized interest or an allowance for funds used during construction, or 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. The Utility had capitalized interest and AFUDC of approximately $29 million at December 31, 2003, $27 million at December 31, 2002 and $18 million at December 31, 2001.

Depreciation The Utility s composite depreciation rate was 3.42% in 2003, 3.42% in 2002 and 3.63% in 2001.

	Gross Plant (in millions)	Estimated useful lives
Electricity generating facilities	$ 1,543	15 to 50 years
Electricity distribution facilities	13,315	16 to 63 years
Electricity transmission	3,418	27 to 65 years
Natural gas distribution facilities	4,499	28 to 49 years
Natural gas transportation	2,365	25 to 45 years
Natural gas storage	280	25 to 48 years
Other	3,403	5 to 40 years
Total	$28,823	

The useful lives of the Utility s property, plant and equipment are authorized by the CPUC. Depreciation rates include a component for the cost of asset retirement net of salvage value. The Utility has a separate rate component for the accrual of its recorded obligation for nuclear decommissioning, which is included in depreciation, amortization and decommissioning expense in the accompanying Consolidated Statements of Operations.

The Utility charged the original cost of retired plant and removal costs less salvage value to accumulated depreciation upon retirement of plant in service for the Utility s lines of business that apply SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, as amended, or SFAS No. 71, which include electricity and natural gas distribution, electricity transmission, and natural gas transportation and storage.

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

Capitalized Software Costs The Utility capitalizes costs incurred during the application development stage of internal use software projects to property, plant and equipment. Capitalized software costs totaled $271 million at December 31, 2003 and $301 million at December 31, 2002, net of accumulated amortization of approximately $158 million at December 31, 2003 and $120 million at December 31, 2002. The Utility 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 and recovery.

Impairment of Long-Lived Assets

The carrying values of long-lived assets are evaluated in accordance with the provisions of SFAS No. 144. SFAS No. 144 became effective at the beginning of 2003 and supersedes SFAS No. 121, Accounting for the Impairment or Disposal of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of, and the accounting and reporting provisions of Accounting Principles Board Opinion No. 30, Reporting the Results of Operations for a Disposal of a Segment of a Business. The adoption of SFAS No. 144 did not have a material impact on the consolidated financial position, results of operations or cash flows of the Utility.

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 are reported as interest expense.

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.

The Utility uses 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, accounts payable, customer deposits and the Utility s variable rate pollution control loan agreements approximate their carrying values as of December 31, 2003 and 2002;

The fair values of rate reduction bonds, preferred stock and 7.90% deferrable interest subordinated debentures were determined based on quoted market prices; and

The fair value of debt for which no market quotation is readily available, was determined with the assistance of third-party experts and using estimates of borrowing rates currently available to the Utility for instruments of similar maturity. The fair value of a small portion of the Utility s debt was determined using the present value of future cash flows.

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

	At December 31,			
	2003		2002	
(in millions)	Carrying amount	Fair value	Carrying amount	Fair value
Long-term debt (Note 3)	$4,839	$4,905	$5,120	$4,906
Rate reduction bonds (Note 4)	1,160	1,252	1,450	1,580
Preferred stock with mandatory redemption provisions (Note 6)	137	167	137	132

Regulation and Statement of Financial Accounting Standards No. 71

The Utility 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. SFAS No. 71 applies to all of the Utility s operations except for its generation operations and a natural gas pipeline expansion project. The Utility is regulated by the CPUC, the FERC and the Nuclear Regulatory Commission, or 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.

To the extent that portions of the Utility s operations cease to be subject to SFAS No. 71 or recovery is no longer probable as a result of changes in regulation or the Utility s competitive position, the related regulatory assets and liabilities would be written off.

Regulatory Assets

Regulatory assets comprise the following:

(in millions)	Balance at December 31, 2003	2002
Rate reduction bond assets	$1,054	$1,346
Regulatory assets for deferred income tax	324	229
Unamortized loss, net of gain, on reacquired debt	277	299
Post-transition period contract termination costs	151	
Environmental compliance costs	139	102
Other, net	56	35
Total regulatory assets	$2,001	$2,011

Regulatory assets are charged to expense during the period that the costs are reflected in regulated revenues.

The Utility s regulatory asset related to rate reduction bonds is amortized simultaneously with the amortization of the rate reduction bonds liability, and is expected to be recovered by the end of 2007. The Utility s regulatory assets related to deferred income tax will be recovered over the period of reversal of the accumulated deferred taxes to which they relate. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover deferred income tax-related regulatory assets over periods ranging from 1 to 37 years. The Utility s regulatory asset related to the unamortized loss, net of gain, on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from 1 to 23 years. The Utility s regulatory asset relating to post-transition period contract termination costs is being amortized and collected in rates on a straight-line basis until the end of September 2014, the contract s original termination date. The Utility s regulatory asset related to environmental compliance represents the portion of the Utility s environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount will be recovered in future rates.

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

Regulatory Liabilities

Regulatory liabilities comprise the following:

(in millions)	Balance at December 31, 2003	2002
Cost of removal obligation	$1,810	$1,621
Employee benefit plans	925	1,102
Asset retirement costs	584	
Public purpose programs	185	182
Rate reduction bonds	175	102
Surcharge liability	125	
Other	175	75
Total regulatory liabilities	$3,979	$3,082

The Utility s regulatory liabilities related to costs of removal represent revenues collected for asset removal costs that the Utility expects to incur in the future. Historically, these removal costs have been recorded in accumulated depreciation; however, as a result of recent guidance from the staff of the SEC, the Utility reclassified this obligation to a regulatory liability during 2003. The regulatory liability associated with over-recovery of asset retirement costs represents timing differences between the recognition of nuclear decommissioning obligations in accordance with GAAP applicable to non-regulated entities, based on the adoption of SFAS No. 143 on January 1, 2003, and the amounts recognized for ratemaking purposes. The Utility s regulatory liabilities related to employee benefit plan expenses represent the cumulative differences between expenses recognized for financial accounting purposes and expenses recognized for ratemaking purposes. These balances will be charged against expense to the extent that future financial accounting expenses exceed amounts recoverable for regulatory purposes. The Utility s regulatory liability related to public purpose programs represents revenues designated for public purpose program costs that are expected to be incurred in the future. The Utility s regulatory liability for rate reduction bonds represents the deferral of over-collected revenue associated with the rate reduction bonds that the Utility expects to return to ratepayers in the future.

The Utility s regulatory liability related to surcharge revenues represents the estimated amount of previously collected surcharge revenues expected to be refunded to customers based upon current proceedings at the CPUC. In early January 2004, the CPUC issued a decision finding that the rate freeze mandated by AB 1890 ended on January 18, 2001. In mid-January 2004, the Utility entered into a rate design settlement agreement, or rate design settlement, with representatives of major customer groups that addresses revenue allocation and rate design issues associated with the decrease in the Utility s revenue requirement resulting from the Settlement Agreement, DWR revenue requirements, and other CPUC actions. On February 11, 2004, a proposed decision was issued that would adopt the rate design settlement with a modification for DWR revenues. This proposed decision, if approved by the CPUC, combined with the January 2004 CPUC decision regarding the rate freeze, provides that the Utility will no longer collect the frozen rates and surcharges. Instead, it will collect the regulatory assets arising from the Settlement Agreement, as amortized into rates, and the revenue requirements established by the 2003 general rate case, or GRC, settlement discussed below as well as revenue requirements established in other proceedings. The CPUC s proposed decision adopts the Utility s request to revise electricity rates reflecting the terms of the rate design settlement based on the Utility s overall forecast revenue requirements for 2004. If ultimately approved, the Utility s electricity customers would receive an electricity rate reduction of approximately 8.0%, on average, in March 2004, or shortly thereafter retroactive to January 1, 2004. The Utility expects that as a result of this rate reduction, electricity operating revenues would decrease by approximately $799 million compared to revenues generated at current rates. As a result of the anticipated rate decrease incorporating a refund of some surcharge revenues collected in 2003, the Utility has established a $125 million regulatory liability at December 31, 2003. In addition, if the 2003 GRC settlement is not approved, the net average reduction in electricity rates and associated reduction in electricity operating revenue will be even greater.

Regulatory Balancing Accounts

Sales balancing accounts accumulate differences between recorded revenues and revenues the Utility is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs the Utility is authorized to recover through rates. Under-collections that are probable of recovery are recorded as regulatory balancing account assets. Over-collections are recorded as regulatory balancing account liabilities. The Utility s regulatory balancing accounts accumulate balances until they are refunded to or received from the Utility s customers through authorized rate adjustments.

As a result of the California energy crisis discussed in Note 2, the Utility could no longer conclude that power generation and procurement-related balancing accounts met the requirements of SFAS No. 71. However, the Utility continues to record balancing accounts associated with its electricity transmission and distribution and natural gas transportation businesses.

In 2002 and 2003, the CPUC ordered the Utility to create certain electricity balancing accounts to track specific electric-related amounts, including shortfalls from baseline allowance increases and costs related to the self-generation incentive program, for which the CPUC has not yet determined the recovery method for these costs. In the decisions ordering the creation of these balancing accounts, the CPUC indicated that the recovery method of these amounts would be determined in the future. Because the Utility cannot conclude that the amounts in these balancing accounts are considered probable of recovery in future rates, the Utility has reserved these balances by recording a charge against earnings. As of December 31, 2003, the reserve for these balances was approximately $200 million.

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

(in millions)	Balance at December 31, 2003	2002
Natural gas revenue balancing accounts	$ 23	$ 38
Natural gas cost balancing accounts	55	60
Electricity revenue balancing accounts	75	
Electricity distribution cost balancing accounts	95	
Total	$248	$ 98

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

(in millions)	Balance at December 31, 2003	2002
Natural gas revenue balancing accounts	$ 13	$ 4
Natural gas cost balancing accounts	158	226
Electricity transmission and distribution revenue balancing accounts	6	98
Electricity transmission cost balancing accounts	9	36
Total	$186	$364

The Utility expects to collect from or refund to its customers the balances included in current balancing accounts receivable and payable within the next twelve months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next twelve months are included in non-current regulatory assets and liabilities.

Revenue Recognition

Electricity revenues, which are comprised of generation, transmission, and distribution services, were billed to the Utility s customers at the CPUC-approved bundled electricity rate. Natural gas revenues, which are comprised of transmission and distribution services, are also billed at CPUC-approved rates. The Utility s revenues are recognized as natural gas and electricity are delivered, and include amounts for services rendered but not yet billed at the end of each year.

As further discussed in Note 11, in January 2001, the California Department of Water Resources, or DWR, began purchasing electricity to meet the portion of demand of the California investor-owned electric utilities that was not being satisfied from their own generation facilities and existing electricity contracts. Under California law, the DWR is deemed to sell the electricity directly to the Utility s retail customers, not to the Utility. Therefore, the Utility acts as a pass-through entity for electricity purchased by the DWR on behalf of its customers. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts from its electricity revenues the amounts passed through to the DWR. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers at the CPUC-approved remittance rate. These pass-through amounts are excluded from the Utility s electricity revenues in its Consolidated Statements of Operations.

Accounting for Price Risk Management Activities

The Utility engages in price risk management activities for non-trading purposes. Non-trading derivative instruments designated as cash flow hedges are entered into to hedge variable price risk associated with the purchase and sale of commodities and to hedge variable interest rates on long-term debt. Price risk management activities include the continuation of power forward contracts that were in existence before the Utility s Chapter 11 proceeding, new power contracts entered into since January 1, 2003 when the Utility resumed procurement of electricity, contracts related to the natural gas portfolio and interest rate hedges related to the issuance of debt under the Utility s Plan of Reorganization.

Derivative instruments associated with non-trading activities include forward contracts, futures, swaps, options and other contracts. They are accounted for at fair value unless they qualify for the normal purchases and sales exemption as further discussed below.

Derivative instruments that are recorded on the Utility s Consolidated Balance Sheets are presented in other current assets. For derivative instruments designated as cash flow hedges associated with non-regulated operations, unrealized gains or losses related to the effective portion of the change in the fair value of the derivative instrument is recorded in accumulated other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of the change in the fair value of the derivative instrument is recognized immediately in earnings. For derivative instruments designated as cash flow hedges associated with the Utility s regulated operations, unrealized gains and losses related to the effective and ineffective portions of the change in the fair value of the derivative instrument are deferred and recorded in regulatory liabilities and regulatory assets to the extent they are recoverable in future rates.

The Utility discontinues hedge accounting prospectively if it determines that the derivative instrument no longer qualifies as an effective hedge, or when the forecasted transaction is no longer probable of occurring. If hedge accounting is discontinued because the derivative instrument no longer qualifies as an effective hedge, then the derivative instrument continues to be reflected at fair value, with any subsequent changes in fair value recognized immediately in earnings. Gains and losses related to a derivative instrument for which hedge accounting has been discontinued that were previously recorded in accumulated other comprehensive income will remain in accumulated other comprehensive income until the hedged item is recognized in earnings, unless the forecasted transaction is no longer probable of occurring. If hedge accounting is discontinued because the forecasted transaction is no longer probable of occurring, then the gains and losses from the derivative instrument that were previously recorded in accumulated other comprehensive income will be immediately recognized in earnings. When the hedged item matures or is sold, the gains and losses deferred in accumulated other comprehensive income are recognized in earnings.

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

Non-trading derivative instruments that are not designated as hedges or that are not eligible for the normal purchases and sales exception are adjusted to fair value through income.

The Utility estimates the fair value of its contracts using the mid-point of quoted bid and ask forward prices, including quotes from counterparties, brokers, electronic exchanges and published indices, supplemented by online price information from news services. When market data is not available, the Utility uses models to estimate fair value.

The Utility has derivative commodity instruments for the physical delivery of purchase and sale quantities transacted in the normal course of business. These derivative instruments 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. Derivative instruments treated as normal purchases or sales are recorded and recognized in income using accrual accounting. Therefore, revenues are recognized as earned and expenses are recognized as incurred.

The Utility has commodity contracts that are not derivative instruments. Revenues are recorded as earned and expenses are recognized as incurred.

Stock-Based Compensation

The Utility accounts for stock-based compensation using the intrinsic value method in accordance with the provisions of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees, as allowed by SFAS No. 123, Accounting for Stock-Based Compensation, or SFAS No. 123, as amended by SFAS No. 148, Accounting for Stock-Based Compensation-Transition and Disclosures, an Amendment of FASB Statement No. 123, or SFAS No. 148. Under the intrinsic value method, the Utility 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. If compensation expense had been recognized using the fair value-based method under SFAS No. 123 and using valuation assumptions disclosed in Note 10, then the Utility s pro forma consolidated earnings would have been as follows:

	Year Ended December 31,		
(in millions)	2003	2002	2001
Net Earnings:			
As reported	$901	$1,794	$1,015
Deduct: Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effects	(8)	(7)	(7)
Pro forma	$893	$1,787	$1,008

Reclassifications

Certain amounts in the 2002 and 2001 Consolidated Financial Statements have been reclassified to conform to the 2003 presentation. These reclassifications did not affect the consolidated net income reported by the Utility for the periods presented.

Asset Removal Costs and Decommissioning Obligations

As described in Accounting for Asset Retirement Obligations above, the Utility collects estimated removal costs associated with certain assets (non-SFAS No. 143 asset retirement obligations) in rates through depreciation in accordance with regulatory treatment. Also, as described above, based upon guidance provided by the staff of the SEC, the Utility reclassified its liability related to these costs of asset removal as of December 31, 2003, and previously provided disclosure regarding the amount of the liability that was included in accumulated depreciation as of December 31, 2002. On February 23, 2004, the staff of the SEC provided further guidance requiring that prior year balances also be reflected as separate liabilities instead of as part of accumulated depreciation. As described above, the Utility s $1.6 billion asset removal liability at December 31, 2002, has been reclassified from accumulated depreciation to regulatory liabilities in the Consolidated Balance Sheets included herein.

In addition, based upon this additional guidance from the staff of the SEC the Utility has reclassified its nuclear generation and certain fossil generation facilities decommissioning obligations of approximately $1.4 billion, which were included within accumulated depreciation, as separate noncurrent liabilities at December 31, 2002. These obligations, after recording the previously described effects of implementing SFAS No. 143, were reclassified as asset retirement obligations in 2003.

There was no impact on the Utility s consolidated statements of operations, cash flows, or shareholders equity as a result of these reclassifications.

NOTE 2: THE UTILITY CHAPTER 11 FILING

On April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Northern District of California. The Utility has retained control of its assets and is authorized to operate its business as a debtor-in-possession during its Chapter 11 proceeding. PG&E Corporation and subsidiaries of the Utility, including PG&E Funding, LLC (which issued rate

reduction bonds) and PG&E Holdings, LLC (which holds stock of the Utility), are not included in the Utility s Chapter 11 proceeding.

Claims filed in the Chapter 11 proceeding totaled approximately $51.5 billion. Of these claims, approximately $9.8 billion related to ISO, Power Exchange, or PX, and generator claims. Under a bankruptcy court order the aggregate allowable amount of ISO, PX and generator claims is limited to approximately $1.6 billion after giving effect to approximately $200 million in pre-petition offset. The Utility expects that this approximately $1.6 billion amount will be further reduced as a result of certain proceedings pending at the FERC. Of the approximately $43.3 billion of filed claims that remained, approximately $23.8 billion has been disallowed by the bankruptcy court due to objections, claim withdrawals and agreements with claimants. The Utility has objected to, or intends to object to, approximately $900 million of the remaining approximately $19.5 billion of filed claims. In addition, of the remaining approximately $19.5 billion of filed claims, approximately $5.5 billion are expected to pass through the Chapter 11 proceeding and be satisfied in the ordinary course of business. Since the Utility s filing under Chapter 11 in April 2001, the Utility has made approximately $2.0 billion in claims-related principal payments.

The Utility has recorded its estimate of all valid claims at December 31, 2003 as approximately $9.5 billion of liabilities subject to compromise, including interest on disputed claims and approximately $2.7 billion of long-term debt. At December 31, 2002, the Utility had recorded approximately $9.4 billion of liabilities subject to compromise. The increase from $9.4 billion is mainly due to interest accruals during the twelve months ended December 31, 2003.

The bankruptcy court has authorized certain payments and actions necessary for the Utility to continue its normal business operations while operating as a debtor-in-possession. For example, the Utility is authorized to pay employee wages and benefits, amounts due under contracts with the majority of qualifying facilities, environmental remediation expenses and expenditures related to property, plant and equipment. In addition, the Utility is authorized to refund certain customer deposits, use certain bank accounts and make cash collateral deposits and assume responsibility for various hydroelectric contracts. The Utility also has received permission from the bankruptcy court to make payments on pre- and post-petition interest on certain claims, pre-petition secured debt that has matured and certain other claims.

The Utility has agreed to pay pre- and post-petition interest on liabilities subject to compromise at the rates set forth below.

(in millions)	Amount Owed	Agreed Upon Interest Rate at December 31, 2003 (per annum)
Commercial paper claims	$ 873	8.216%
Floating rate notes	1,240	8.333%
Senior notes	680	10.375%
Medium-term notes	287	6.560% to 9.200%
Revolving line of credit claims	938	8.750%
Pollution control bonds	814	1.300% to 5.350%
Qualifying facilities	45	5.000%
Other claims	4,625	3.160% to 12.000%
Liabilities subject to compromise at December 31, 2003	$9,502	

Since the Utility did not emerge from Chapter 11 on or before September 15, 2003, the interest rates for commercial paper claims, floating rate notes, senior notes, medium-term notes and revolving line of credit claims increased 0.75% over the originally agreed upon rates for periods on and after September 15, 2003. The interest rates for these claims will increase by an additional 0.375% if the effective date of a plan of reorganization does not occur on or before March 15, 2004. For other claims, the Utility has recorded interest at the contractual or FERC-tariffed interest rate. When those rates do not apply, the Utility has recorded interest at the federal judgment rate.

Plan of Reorganization

In September 2001, PG&E Corporation and the Utility proposed a plan of reorganization that would have disaggregated the Utility s businesses. In April 2002, the CPUC, later joined by the Official Committee of Unsecured Creditors, proposed an alternate plan of reorganization that would not have disaggregated the Utility s businesses. On December 19, 2003, the CPUC, PG&E Corporation and the Utility entered into a settlement agreement, or the Settlement Agreement, that contemplated a new plan of reorganization to supersede the competing plans. Under the Settlement Agreement, the Utility remains vertically integrated. On December 22, 2003, the bankruptcy court confirmed the new plan of reorganization, or the Plan of Reorganization, which fully incorporates the Settlement Agreement. The Utility expects to pay all allowed creditor claims (except for the claims of holders of pollution control-related bond obligations that will be reinstated) from the proceeds of a public offering of long-term debt, cash on hand, and draws on credit facilities. The Utility also will establish one or more escrow accounts for disputed claims and deposit cash in these accounts. Under the Plan of Reorganization, allowed environmental, fire suppression, pending litigation and tort claims, and workers compensation claims will be satisfied by the Utility in the ordinary course of business.

On January 20, 2004, several parties filed applications with the CPUC requesting that the CPUC rehear and reconsider its decision approving the Settlement Agreement on the basis that the Settlement Agreement does not comply with California law. Although the CPUC is not required to act on these applications within a specific time period, if the CPUC has not acted on an application within 60 days, that application may be deemed denied for purposes of seeking judicial review. In addition, the two CPUC commissioners who did not vote to approve the Settlement Agreement and a municipality have filed appeals of the bankruptcy court s confirmation order in the U.S. District Court for the Northern District of California, or the District Court, citing similar objections to those included in the request for rehearing and reconsideration of the CPUC s decision. On January 5, 2004, the bankruptcy court denied a request to stay the implementation of the Plan of Reorganization until the appeals are resolved. The District Court will set a schedule for briefing and argument of the appeals at a later date. No additional parties may request rehearings or make appeals of the CPUC s approval of the Settlement Agreement or the bankruptcy court s confirmation order. PG&E Corporation and the Utility cannot predict the timing and outcome of the requests for rehearing and appeals.

The 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 the Plan of Reorganization are effected or executed;

The Utility and PG&E Corporation have received all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions or documents that the Utility and PG&E Corporation determine are necessary to implement the Plan of Reorganization;

The Plan of Reorganization has not been modified in a material way since the date of confirmation;

The Utility has consummated the sale of the debt securities provided for under the Plan of Reorganization;

Moody s Investors Service, or Moody s, has issued an issuer rating for the Utility of not less than Baa3 and Standard & Poor s, or S&P, has issued long-term issuer credit ratings for the Utility of not less than BBB-;

Moody s has issued a credit rating of not less than Baa3 for the debt securities provided for under the Plan of Reorganization and S&P has issued a credit rating of not less than BBB- for the debt securities provided for under the Plan of Reorganization;

The CPUC has given final approval of the Settlement Agreement;

The Utility, PG&E Corporation and the CPUC have executed and delivered the Settlement Agreement;

The CPUC has given final approval for all of the financings, securities and accounts receivable programs provided for in the Plan of Reorganization; and

The CPUC has given final approval for all rates, tariffs and agreements necessary to implement the Plan of Reorganization.

As described above, the Plan of Reorganization provides that it will not become effective unless and until the CPUC has given final approval of the Settlement Agreement, the financings, securities and accounts receivable programs provided for in the Plan of Reorganization and all rates, tariffs and agreements necessary to implement the 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 by the Utility and PG&E Corporation to constitute final approval. Thus, the terms of the Plan of Reorganization permit the Utility and PG&E Corporation to cause the Plan of Reorganization to become effective (and permit the Utility to issue the debt securities provided for under the Plan of Reorganization) while the CPUC s approvals are subject to pending appeals or further rights of appeal. In addition, the Plan of Reorganization provides that the Utility may waive the conditions described under the first five bullets listed above.

Principal Terms of the Settlement Agreement

The Settlement Agreement contains a statement of intent that it is in the public interest to restore the Utility to financial health and maintain and improve the Utility s financial condition in the future to ensure that the Utility is able to provide safe and reliable electricity and natural gas to its customers at just and reasonable rates. In addition, the Settlement Agreement includes a statement of intent that it is fair and in the public interest to allow the Utility to recover prior uncollected costs over a reasonable time and to provide for the Utility s shareholders to earn a reasonable rate of return on the Utility s business.

The principal terms of the Settlement Agreement are:

Regulatory Asset

The Settlement Agreement establishes a $2.21 billion, after-tax, regulatory asset (which is equivalent to an approximately $3.7 billion, pre-tax, regulatory asset), or the Regulatory Asset, as a new, separate and additional part of the Utility s rate base that will be amortized on a mortgage-style basis over nine years beginning January 1, 2004. Under this amortization methodology, annual after-tax collections of a $2.21 billion regulatory asset are estimated to range from approximately $140 million in 2004 to approximately $380 million in 2012, although these amounts will be reduced as discussed below. The Regulatory Asset will be recognized when it meets the SFAS No. 71 accounting criteria for probability of recovery in rates. Upon recognition of the Regulatory Asset the Utility will reflect a one-time non-cash gain equal to the Regulatory Asset. The Regulatory Asset will be fully amortized by the end of 2012.

The unamortized balance of the Regulatory Asset will earn a rate of return on its equity component of no less than 11.22% annually for its nine-year term and, after the equity component of the Utility s capital structure reaches 52%, the authorized equity component of this regulatory asset will be no less than 52% for the remaining term. The rate of return on the Regulatory Asset will be reduced if the Utility completes the refinancing discussed below. The equity and debt components of the Utility s rate of return will be eliminated. Instead the Utility would collect from customers amounts sufficient to service the securitized debt.

The net after-tax amount of any refunds, claim offsets or other credits the Utility receives from energy suppliers relating to specified procurement costs incurred during the California energy crisis and arising from the settlement of CPUC litigation against El Paso Natural Gas Company, or El Paso, related to any electricity (but not natural gas) refunds will reduce the outstanding balance of the Regulatory Asset. On January 26, 2004 in a filing with the CPUC, the Utility proposed to reduce the Regulatory Asset by approximately $189 million, after-tax, for these matters.

Ratemaking Matters

The CPUC deemed the Utility s adopted 2003 electricity generation rate base of approximately $1.6 billion just and reasonable and not subject to modification, adjustment or reduction, except as necessary to reflect capital expenditures and changes in authorized depreciation. This reaffirmation would allow for the recognition of an additional after-tax regulatory asset of approximately $800 million (which is equivalent to an approximately $1.3 billion pre-tax regulatory asset). This regulatory asset and an equivalent one-time non-cash gain will be recorded when it meets the probability requirements of SFAS No. 71. The individual components of the regulatory assets will be amortized over their respective lives, with a weighted average life of approximately 16 years.

The CPUC will timely act upon the Utility s applications to collect in rates prudently incurred costs of (including return of and return on) any new and reasonable investment in utility plant and assets and will timely adjust the Utility s rates to ensure that the Utility collects in its rates fixed amounts to service existing rate reduction bonds, Regulatory Asset amortization and return, and base revenue requirements. The Settlement Agreement provides that the CPUC will not discriminate against the Utility because of the Utility s Chapter 11 proceeding and the Utility s previous actions concerning the energy crisis.

The CPUC will set the Utility s capital structure and authorized return on equity in its annual cost of capital proceedings in its usual manner. However, from January 1, 2004 until Moody s has issued an issuer rating for the Utility of not less than A3 or S&P has issued a long-term issuer credit rating for the Utility of not less than A-, the Utility s authorized return on equity will be no less than 11.22% per year and its authorized equity ratio for ratemaking purposes will be no less than 52%. However, for 2004 and 2005, the Utility s authorized equity ratio will be the greater of the proportion of equity approved in the Utility s 2004 and 2005 cost of capital proceedings, or 48.6%.

The Utility s retail electricity rates were maintained at current levels through December 31, 2003. The Settlement Agreement includes a statement of intent that as a result of the Settlement Agreement and the Plan of Reorganization, retail electricity rates may be reduced in January 2004 with future reductions expected thereafter.

The CPUC also agreed to act promptly on certain of the Utility s pending ratemaking proceedings, including the Utility s pending 2003 general rate case, or GRC. The outcome of these proceedings may result in the establishment of additional regulatory assets on the Utility s Consolidated Balance Sheets.

Refinancing Supported by a Dedicated Rate Component

Under the Settlement Agreement, PG&E Corporation and the Utility agreed to seek to refinance the remaining unamortized pre-tax balance of the Regulatory Asset and related federal, state and franchise taxes, up to a total of $3.0 billion, as expeditiously as practicable after the effective date of the Plan of Reorganization using a securitized financing supported by a dedicated rate component, provided the following conditions are met:

- Authorizing California legislation satisfactory to the CPUC, The Utility Reform Network, or TURN, and the Utility is passed and signed into law allowing securitization of the Regulatory Asset and associated federal and state income and franchise taxes and providing for the collection in the Utility s rates of any portion of the associated tax amounts not securitized;

- The CPUC determines that, on a net present value basis, the refinancing would save customers money over the term of the securitized debt compared to the Regulatory Asset;

- The refinancing will not adversely affect the Utility s issuer or debt credit ratings; and

- The Utility obtains, or decides it does not need, a private letter ruling from the Internal Revenue Service, or IRS, confirming that neither the refinancing nor the issuance of the securitized debt is a presently taxable event.

The Utility would be permitted to complete the refinancing in up to two tranches up to one year apart, and would issue sufficient callable debt or debt with earlier maturities as part of the Plan of Reorganization to accommodate the refinancing supported by a dedicated rate component. Upon refinancing with securitization, the equity and debt components of the Utility s rate of return on the Regulatory Asset would be eliminated. Instead the Utility would collect from customers amounts sufficient to service the securitized debt. The Utility would use the securitization proceeds to rebalance its capital structure in order to maintain the capital structure provided for under the Settlement Agreement.

California Department of Water Resources Contracts

The Settlement Agreement provides that the CPUC will not require the Utility to accept an assignment of, or to assume legal or financial responsibility for, the DWR power purchase contracts, unless each of the following conditions has been met:

- After assumption, the Utility s issuer credit rating by Moody s will be no less than A2 and the Utility s long-term issuer credit rating from S&P will be no less than A;

- The CPUC first makes a finding that the DWR power purchase contracts to be assumed are just and reasonable; and

- The CPUC has acted to ensure that the Utility will receive full and timely recovery in its retail electricity rates of all costs associated with the DWR power purchase contracts to be assumed without further review.

Under the Settlement Agreement, the CPUC retains and, after any assumption of the DWR contracts, will retain the right to review the prudence of the Utility s administration and dispatch of the DWR contracts consistent with applicable law.

Headroom

The CPUC agreed and acknowledged that the headroom, surcharge and base revenues accrued or collected by the Utility through and including December 31, 2003 are the property of the Utility s Chapter 11 estate, have been or will be used for utility purposes, including to pay creditors in the Utility s Chapter 11 proceeding, and have been included in the Utility s retail electricity rates consistent with state and federal law. The Settlement Agreement defines headroom as the Utility s total net after-tax income reported under GAAP, less earnings from operations (a non-GAAP financial measure that has been historically reported by the Utility in its earnings press release), plus after-tax amounts accrued for Chapter 11-related administration and Chapter 11-related interest costs, all multiplied by 1.67, provided that the calculation reflects the outcome of the Utility s 2003 GRC. The Settlement Agreement provides that if headroom revenue accrued by the Utility during 2003 is greater than $875 million, pre-tax, the Utility will refund the excess to ratepayers.

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 Plan of Reorganization, or the date the CPUC decision approving the Settlement Agreement is no longer subject to appeal, the Utility will dismiss with prejudice its case against the CPUC Commissioners related to the federal filed rate doctrine, withdraw the original plan of reorganization and dismiss certain other pending proceedings. In exchange, the CPUC has established and authorized the collection of the Regulatory Asset and the Utility s rate base for its electricity generation, and, on or as soon as practicable after the effective date, the CPUC will resolve phase 2 of the pending Annual Transition Cost Proceeding, in which the CPUC is reviewing the reasonableness of the Utility s procurement costs incurred during the energy crisis, with no adverse impact on the Utility s requested cost recovery.

On or as soon as practicable after the later of the effective date of the Plan of Reorganization or the date the CPUC decision approving the Settlement Agreement is no longer subject to appeal, PG&E Corporation, the Utility, 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 Assembly Bill, 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 Settlement Agreement, the Utility has 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. The Utility also has suspended all actions to obtain or transfer licenses, permits and franchises to implement the original plan of reorganization. On the effective date of the Plan of Reorganization, or as soon thereafter as practicable, the Utility and PG&E Corporation will withdraw or abandon all applications for these regulatory approvals. In addition, the Utility and PG&E Corporation have agreed that for the term of the Regulatory Asset, neither the Utility nor PG&E Corporation, nor their respective affiliates, will make any filings under Sections 4, 5 or 7 of the Natural Gas Act to transfer ownership or ratemaking jurisdiction over the Utility s intrastate gas pipeline and storage facilities, which means that these facilities will remain primarily subject to CPUC regulation. The Utility and PG&E Corporation have also agreed that the CPUC has jurisdiction to review and approve any proposal to dispose of the Utility s property necessary or useful in the performance of the Utility s duties to the public.

Environmental Measures

The Utility agreed to implement three environmental enhancement measures:

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

The Utility will establish a California non-profit corporation to oversee the environmental enhancements associated with these lands and fund it with $100 million in cash over ten years, although the Utility will be entitled to recover these payments in rates; and

The Utility will create a non-profit corporation funded with $30 million payable by the Utility over five years, with no recovery of these payments in rates, dedicated to support research and investment in clean energy technology, primarily in the Utility s service territory.

Of the approximately 140,000 acres referred to above, approximately 44,000 acres may be either donated or encumbered with conservation easements. The remaining land contains the Utility s or a joint licensee s hydroelectric generation facilities and may only be encumbered with conservation easements.

Term and Enforceability

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

Fees and Expenses

The Settlement Agreement requires the Utility to reimburse the CPUC for its professional fees and expenses incurred in connection with the Chapter 11 proceeding once the Plan of Reorganization is confirmed. These amounts will be recovered from customers over a reasonable time of up to four years. This accrual will be recorded when the applicable GAAP requirements are met. PG&E Corporation s professional fees and expenses incurred in connection with the Chapter 11 proceeding will not be reimbursed by the Utility or from the Utility s customers.

Financial Summary

Implementation of the Plan of Reorganization is subject to various conditions, including the consummation of the public offering of long-term debt, the receipt of investment grade credit ratings and final CPUC approval of the Settlement Agreement. Under the terms of the Plan of Reorganization PG&E Corporation and the Utility may determine that the CPUC order approving the Settlement Agreement is final even if appeals are pending. There can be no assurance that the Settlement Agreement will not be modified on rehearing or appeal or that the Plan of Reorganization will become effective. Until certain conditions or events regarding the effectiveness of the Plan of Reorganization discussed above are resolved further, the Utility does not believe the applicable accounting probability standard under SFAS No. 71 needed to record the regulatory assets at December 31, 2003, has been met.

NOTE 3: DEBT

Long-Term Debt

The following table summarizes the Utility s long-term debt that matures in one year or more from the date of issuance:

(in millions)	December 31, 2003	December 31, 2002
Long-term debt		
First and refunding mortgage bonds:		
5.85% to 8.80% bonds, maturing 2004-2026	$2,764	$3,044
Unamortized discount net of premium	(23)	(24)
Total mortgage bonds	2,741	3,020
Less: current portion	310	281
Total long-term debt, net of current portion	2,431	2,739
Total long-term debt, net of current portion	$3,314	$3,715
Long-term debt subject to compromise		
Senior notes, 10.38%, due 2005	$ 680	$ 680
Pollution control loan agreements, variable rates, due 2026	614	614
Pollution control loan agreement, 5.35%, due 2016	200	200
Unsecured medium-term notes, 6.56% to 9.20%, due 2004-2014	287	287
Deferrable interest subordinated debentures, 7.90%, due 2025	300	300
Other Utility long-term debt	17	19
Total long-term debt subject to compromise	$2,098	$2,100

The following information about the Utility s debt reflects the terms of the debt as of December 31, 2003. As discussed in Note 2 The Plan of Reorganization, substantially all of this debt will be refinanced with the proceeds of a public offering of long-term debt, cash on hand and draws on credit facilities.

First and Refunding Mortgage Bonds

The Utility issued first and refunding mortgage bonds, or Mortgage Bonds, in various series that bear annual interest rates ranging from 5.85% to 8.80%. All real property and substantially all personal property of the Utility are subject to the lien of the mortgage, and the Utility is required to make semi-annual sinking fund payments for the retirement of the Mortgage Bonds. While in Chapter 11, the Utility 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 that matured in March 2002 and $281 million in August 2003, and has also approved the payment of interest in accordance with the terms of the Mortgage Bonds. In January 2004, the Utility filed a motion requesting that the bankruptcy court approve the payment of $310 million of Mortgage Bonds maturing in March 2004.

Mortgage Bonds outstanding at December 31, 2003 and 2002 include $345 million of bonds held in trust for the California Pollution Control Financing Authority, or CPCFA, with interest rates ranging from 5.85% to 6.63% and maturity dates ranging from 2009 to 2023.

Senior Notes

In November 2000, the Utility issued $680 million of five-year senior notes, or Senior Notes, bearing an interest rate of 7.38%. The Utility used the net proceeds to repay short-term borrowings incurred to finance power purchases and for other general corporate purposes. These Senior Notes contain interest rate adjustments dependent upon the Utility s unsecured debt ratings.

As a result of the Utility s credit rating downgrades in January 2001, the interest rate on the Senior Notes was increased by 1.75%. In addition, in April 2001, an interest premium penalty of 0.5% was imposed due to the Utility s failure to make a public offering. As a result, the bankruptcy court approved a motion by various unsecured creditors increasing the interest rate on the Senior Notes to 9.63% effective November 1, 2000. The interest rate on the Senior Notes was increased by an additional 0.375% on February 15, 2003 and September 15, 2003 because a Utility plan of reorganization did not become effective on or before those dates. If the effective date of a plan of reorganization does not occur on or before March 15, 2004, the interest rate will increase by an additional 0.375%. In 2001, the Utility s Chapter 11 filing and failure to make payments on the Senior Notes were events of default. In 2002, the bankruptcy court authorized the Utility to make quarterly interest payments on these loans. The Senior Notes are classified as liabilities subject to compromise in the Consolidated Balance Sheets at December 31, 2003 and 2002.

Pollution Control Loan Agreements

Pollution control loan agreements, or Loans, held in trust for the CPCFA totaled $814 million at December 31, 2003 and 2002. Interest rates on $614 million of the Loans are variable. For 2003, the variable interest rates ranged from 0.75% to 1.31%. These Loans are subject to redemption by the holder under certain circumstances. They were secured primarily by irrevocable letters of credit from certain banks, which based on terms negotiated in 2002 and 2003, mature in 2004 through 2005. On March 1, 2001, $200 million of the Loans were converted to a fixed rate obligation with an interest rate of 5.35% with credit supported by bond insurance. In 2002, the bankruptcy court authorized the Utility to make quarterly interest payments on the variable interest rate Loans and semiannual interest payments on the fixed interest rate Loans.

In April and May 2001, $454 million of the Loans were accelerated and the banks paid the amounts due under the letters of credit, resulting in a reimbursement obligation from the Utility to the banks. The Utility had been unable to make principal or interest payments to the banks due to its Chapter 11 filing, an event of default, and accordingly amounts outstanding at December 31, 2003 and 2002, under the related loans are classified as liabilities subject to compromise in the Consolidated Balance Sheets at December 31, 2003 and 2002. In 2002, the bankruptcy court order authorized the Utility to make quarterly interest payments on these loans.

On the effective date of the Plan of Reorganization, the Utility may reinstate $814 million of the Loans.

Unsecured Medium-Term Notes

The Utility has $287 million of outstanding unsecured medium-term notes, or Medium-Term Notes, due from 2004 to 2014 with interest rates ranging from 6.56% to 9.20% at December 31, 2003. The Medium-Term Notes are also in default as the Utility has been unable to make interest and principal repayments on maturity due to its Chapter 11 proceeding. The interest rate on the Medium-Term Notes increased by an additional 0.375% on February 15, 2003 and September 15, 2003 because a plan of reorganization did not become effective on or before those dates. The outstanding principal amounts of the Medium-Term Notes at December 31, 2003 and 2002 are classified as liabilities subject to compromise in the accompanying financial statements. In 2002, the bankruptcy court authorized the Utility to make quarterly interest payments on the Medium-Term Notes.

7.90% Deferrable Interest Subordinated Debentures

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

The Utility s Chapter 11 filing on April 6, 2001, was an event of default under the trust agreement. On March 27, 2002, the bankruptcy court issued an order authorizing the Utility to pay pre- and post-petition interest to holders of certain undisputed claims, including the QUIDS, and on May 6, 2002, the Utility made payments representing interest accrued through February 28, 2002, which was then passed through by the trust to the holders of the QUIPS. Capital I was liquidated by the trustee under the terms of the trust agreement on May 24, 2002. Upon liquidation of Capital I, the holders of the QUIPS received a like amount of QUIDS after satisfaction of Capital I s liabilities to creditors. The terms and interest payments on the QUIDS correspond to the terms and dividend payments of the QUIPS.

The Utility has continued to make scheduled quarterly interest payments. The QUIDS are included in financing debt classified as liabilities subject to compromise on the Utility s Consolidated Balance Sheets at December 31, 2003 and 2002.

Repayment Schedule

At December 31, 2003, the Utility s aggregate amounts of maturing long-term debt as scheduled are reflected in the table below:

(in millions)	2004	2005	2006	2007	2008	Thereafter	Total
Expected maturity date [1]							
Long-term debt:							
Fixed rate obligations	$ 310	$ 289	$	$	$	$2,142	$2,741
Average interest rate	6.25%	5.88%				7.25%	6.99%
Liabilities subject to compromise:							
Fixed rate obligations	225	696	1	1		261	1,184
Average interest rate	8.16%	10.31%	9.45%	9.45%		6.10%	8.97%
7.90% Deferrable interest subordinated debentures						300	300
Variable rate obligations [2]	349	265					614
Rate reduction bonds	290	290	290	290			1,160
Average interest rate	6.44%	6.42%	6.44%	6.48%			6.44%
Total	$1,174	$1,540	$ 291	$ 291	$	$2,703	$5,999

(1) Table is based upon contractual maturity dates

(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 the Utility s lines of credit:

(in millions)	December 31, 2003	2002
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 Agreement	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

Credit Facilities

At December 31, 2003 and 2002, the Utility had $938 million outstanding on a defaulted $1 billion five-year revolving credit facility. The bank terminated its outstanding commitment with the default. The interest rate on the revolving credit facility increased by an additional 0.375% on February 15, 2003 and September 15, 2003 because a plan of reorganization did not become effective on or before those dates. The weighted average interest rate was 8.75% at December 31, 2003 and 8.00% at December 31, 2002. This facility was used to support the Utility s commercial paper program and other liquidity requirements. The outstanding balance is classified as liabilities subject to compromise on the December 31, 2003 and 2002 Consolidated Balance Sheets. In 2002, the bankruptcy court authorized the Utility to make quarterly interest payments on these loans.

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 the Utility to the banks. The weighted average interest rate was 5.50% at December 31, 2003 and 5.75% at December 31, 2002.

Floating Rate Notes

The Utility issued a total of $1.24 billion of 364-day floating rate notes in November 2000, with interest payable quarterly. The interest rate on the floating notes increased by an additional 0.375% on February 15, 2003 and September 15, 2003 because a plan of reorganization did not become effective on or before those dates. The weighted average interest rate was 8.33% at December 31, 2003 and 7.58% at December 31, 2002. These notes were not paid on the maturity date of October 31, 2001, resulting in an event of default. In 2002, an order by the bankruptcy court authorized the Utility to make quarterly interest payments on these loans.

Commercial Paper

The total amount of commercial paper outstanding at December 31, 2003 and 2002 was $873 million. The Utility has been in default on its commercial paper obligations since January 17, 2001. The interest rate on the commercial paper increased by an additional 0.375% on February 15, 2003 and September 15, 2003, because a Utility plan of reorganization did not become effective on or before those dates. The weighted average interest rate on the Utility s commercial paper obligation was 8.22% at December 31, 2003 and was 7.47% at December 31, 2002. In 2002, an order by the bankruptcy court authorized the Utility to make quarterly interest payments on these loans.

NOTE 4: RATE REDUCTION BONDS

In December 1997, PG&E Funding, LLC, a limited liability corporation wholly owned by and consolidated by the Utility, issued $2.9 billion of rate reduction bonds. The proceeds of the rate reduction bonds were used by PG&E Funding, LLC to purchase from the Utility the right, known as transition property, to be paid a specified amount from a non-bypassable charge levied on residential and small commercial customers (Fixed Transition Amount, or FTA, charges). FTA charges are authorized by the CPUC under state legislation and will be paid by residential and small commercial customers until the rate reduction bonds are fully retired. Under the terms of a transition property servicing agreement, FTA charges are collected by the Utility and remitted to PG&E Funding, LLC. As a result of credit rating downgrades in January 2001, on January 8, 2001, the Utility was required to begin remitting these FTA receipts to PG&E Funding, LLC on a daily basis, as opposed to once a month, as had previously been required.

The rate reduction bonds have expected maturity dates ranging from 2004 to 2007, and bear interest at rates ranging from 6.42% to 6.48%. The bonds are secured solely by the transition property and there is no recourse to the Utility.

The total amount of rate reduction bonds principal outstanding was $1.16 billion at December 31, 2003 and $1.45 billion at December 31, 2002. The scheduled principal payments on the rate reduction bonds for the years

2004 through 2007 are $290 million for each year. While PG&E Funding, LLC is a wholly owned consolidated subsidiary of the Utility, it is legally separate from the Utility. The assets of PG&E Funding, LLC are not available to creditors of the Utility and the transition property is not legally an asset of the Utility.

NOTE 5: COMMON STOCK

The Utility is authorized to issue 800 million shares of its $5 par value common stock, of which 321,314,760 shares were issued and outstanding as of December 31, 2003 and 2002. A wholly owned subsidiary of the Utility, PG&E Holdings, LLC, holds 19,481,213 of the outstanding shares. PG&E Corporation and PG&E Holdings, LLC hold all of the Utility s outstanding common stock. Approximately 94% of the outstanding common stock of the Utility that is owned by PG&E Corporation has been pledged as security for PG&E Corporation s 6 7/8% Senior Secured Notes due 2008.

In October 2000, the Utility declared a $110 million common stock dividend to PG&E Corporation and PG&E Holding, LLC. In January 2001, the Utility suspended payment of the declared dividend.

The Utility did not declare or pay common and preferred stock dividends in 2001, 2002 or 2003. Until cumulative dividends on its preferred stock and mandatory preferred sinking fund payments are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

NOTE 6: PREFERRED STOCK

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

At December 31, 2003 and 2002, the Utility had issued and outstanding 5,784,825 shares of non-redeemable preferred stock. Holders of the Utility s 5.0%, 5.5% and 6.0% series of non-redeemable preferred stock have rights to annual dividends ranging from $1.25 to $1.50 per share.

At December 31, 2003 and 2002, the Utility had issued and outstanding 5,973,456 shares of redeemable preferred stock. The Utility s redeemable preferred stock is subject to redemption at its option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2003, annual dividends ranged from $1.09 to $1.76 per share and redemption prices ranged from $25.75 to $27.25 per share.

At December 31, 2003, the Utility s redeemable preferred stock with mandatory redemption provisions consisted of 3 million shares of the 6.57% series and 2.5 million shares of the 6.30% series. These series are redeemable at par value plus accumulated and unpaid dividends through the redemption date. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of the stock outstanding.

The redemption requirements for the Utility s redeemable preferred stock with mandatory redemption provisions for the 6.57% series are approximately $4 million per year from 2002 through 2006, and approximately $55 million in 2007, and for the 6.30% series, approximately $3 million per year from 2004 through 2008, and approximately $47 million in 2009. The Utility s redeemable preferred stock with mandatory redemption provisions may be redeemed early, at the Utility s option, if the Utility pays the specified redemption price plus accumulated and unpaid dividends.

Due to the Utility s Chapter 11 proceeding, the Utility s Board of Directors has not declared or paid preferred stock dividends since January 31, 2001. Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Accumulated and unpaid preferred stock dividends amounted to approximately $80 million as of December 31, 2003, $50 million as of December 31, 2002 and $25 million as of December 31, 2001. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series.

As discussed above in Note 1 under Adoption of New Accounting Policies Accounting for Financial Instruments with Characteristics of Both Liabilities and Equity, the Utility adopted the requirements of SFAS

No. 150 in the third quarter of 2003. As a result, the Utility reclassified approximately $137 million of preferred stock with mandatory redemption provisions as a noncurrent liability in the Utility s Consolidated Balance Sheets. The reclassification did not have an impact on earnings of the Utility.

NOTE 7: RISK MANAGEMENT ACTIVITIES

Non-Trading Activities

On the Utility s Consolidated Balance Sheets, cash flow hedges associated with natural gas commodity price risk are presented at a fair value of $4 million in other current assets. Unrealized losses associated with these cash flow hedges are recorded in regulatory accounts. The natural gas cash flow hedges have varying durations, the longest of which extend through March 2004.

Cash flow hedges associated with interest rate risk are presented at fair value in other current assets. For the portion of the cash flow hedges associated with regulated operations and subject to the provisions of SFAS No. 71, the effective and ineffective portions are recorded in regulatory assets. For the portion of hedges related to non-regulated operations, the change in the fair value of the hedges is recorded in accumulated other comprehensive income and the ineffective portion of the change in the fair value is recorded in interest expense.

The following table presents selected information related to cash flow hedges associated with the interest rate risk related to non-regulated operations at December 31, 2003:

(in millions)	Fair Value on Balance Sheet	Accumulated Other Comprehensive Loss, Net of Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months	Maximum Term
Interest rate	$ 17	$ 3		June 2004

The actual amounts reclassified upon the contractual terms of the contracts or the termination of the hedge position will differ from the expected amounts presented above as a result of changes in interest rates. At December 31, 2002 the Utility did not have any cash flow hedges.

The ineffective portion of changes in amounts of the Utility s cash flow hedges was approximately $4 million for the year ended December 31, 2003. There was no ineffective portion of changes in amounts of the Utility s cash flow hedges for the year ended December 31, 2002.

The Utility has certain non-trading derivative instruments for the purchase of electricity, natural gas and natural gas transportation and storage that are exempt from the SFAS No. 133 fair value requirements under the normal purchases and sales exception and thus have no mark-to-market effect on earnings. Additionally, the Utility holds an immaterial amount of other non-trading derivative instruments that do not qualify for cash flow hedge accounting or the normal purchase and sales exception to SFAS No. 133. These derivative instruments are reported in earnings on a mark-to-market basis.

Credit Risk

Credit risk is the risk of loss that the Utility would incur if customers or counterparties failed to perform their contractual obligations.

The Utility had gross accounts receivable of approximately $2.5 billion at December 31, 2003 and $2.0 billion at December 31, 2002. The majority of the accounts receivable are associated with residential and small commercial customers. Based upon historical experience and evaluation of then-current factors, allowances for doubtful accounts of approximately $68 million at December 31, 2003 and $59 million at December 31, 2002 were recorded against those accounts receivable. In accordance with tariffs, credit risk exposure is limited by requiring deposits from new customers and from those customers whose past payment practices are below standard. The Utility has a regional concentration of credit risk associated with its receivables from residential and small commercial customers in northern and central California. However, material loss due to non-performance from these customers is not considered likely.

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

Credit exposure for the Utility s largest customers and counterparties is calculated daily. If exposure exceeds the established limits, the Utility takes immediate action to reduce the exposure, or obtain additional collateral, or both. Further, the Utility relies heavily on master agreements that require security, referred to as credit collateral, in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

The Utility calculates gross credit exposure for each of its largest customers and counterparties as the current mark-to-market value of the contract (*i.e.*, the amount that would be lost if the counterparty defaulted today) plus or minus any outstanding net receivables or payables, before the application of credit collateral. During 2003 the Utility recognized no material losses due to contract defaults or bankruptcies. At December 31, 2003 there were three counterparties that represented greater than 10% of the Utility s net credit exposure. The Utility had two investment grade counterparties that represented a total of approximately 32% of the Utility s net credit exposure and one below-investment grade counterparty that represented approximately 12% of the Utility s net credit exposure.

The Utility conducts business with customers or vendors mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and gas production companies located in the U.S. and Canada. This concentration of counterparties may impact the Utility s overall exposure to credit risk because counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions.

The schedule below summarizes the Utility s net asset credit risk exposure, as well as the Utility s credit risk exposure to its largest customers or counterparties with a greater than 10% net credit exposure, at December 31, 2003 and December 31, 2002. Credit exposures to Enron subsequent to its filing for Chapter 11 are not included in the information below. See Note 11 for discussion of the Enron Settlement.

(in millions)	Gross Credit Exposure Before Credit Collateral (1)	Credit Collateral	Net Credit Exposure (2)	Number of Largest Customer or Counterparties >10%	Net Exposure of Largest Customer or Counterparties >10%
December 31, 2003	$165	$ 11	$154	3	$ 68
December 31, 2002	288	113	175	2	55

(1) Gross credit exposure equals mark-to-market value, notes receivable and net receivables (payables) where netting is allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value, liquidity or credit reserves. The Utility s gross credit exposure includes wholesale activity only. Retail activity and payables incurred prior to the Utility s Chapter 11 filing are not included. Retail activity at the Utility consists of the accounts receivable from the sale of natural gas and electricity to residential and small commercial customers.

(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.

The schedule below summarizes the credit quality of the Utility s net credit risk exposure to the Utility s largest customers and counterparties at December 31, 2003 and December 31, 2002:

(in millions)	Net Credit Exposure (2)	Percentage of Net Credit Exposure
Credit Quality (1)		
December 31, 2003		
Investment grade (3)	$108	70%
Non-investment grade	46	30%
Total	$154	100%
December 31, 2002		
Investment grade (3)	$111	63%
Non-investment grade	64	37%
Total	$175	100%

(1) Credit ratings are determined by using publicly available information. If provided a guarantee by a higher rated entity (e.g., an affiliate), the rating is determined based on the rating of the 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. The Utility has assessed certain governmental authorities that are not rated through publicly available information as investment grade based upon an internal assessment of credit quality.

NOTE 8: NUCLEAR DECOMMISSIONING

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 Utility s nuclear power facilities consist of two units at the Diablo Canyon power plant and the retired facility at Humboldt Bay Unit 3. For ratemaking purposes, the eventual decommissioning of Diablo Canyon Unit 1 is scheduled to begin in 2021 and to be completed in 2040. Decommissioning of Diablo Canyon Unit 2 is scheduled to begin in 2025 and to be completed in 2041, and decommissioning of Humboldt Bay Unit 3 is scheduled to begin in 2006 and be completed in 2015.

The estimated nuclear decommissioning cost for the Diablo Canyon power plant and Humboldt Bay Unit 3 is approximately $1.83 billion in 2003 dollars (or approximately $5.25 billion in future dollars). These estimates are based on a 2002 decommissioning cost study, prepared in accordance with CPUC requirements and used in the Utility s Nuclear Decommissioning Costs Triennial Proceeding, which is discussed below. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility s nuclear plants. Actual decommissioning costs are expected to vary from this estimate because of changes in assumed dates of decommissioning, regulatory requirements, technology, costs of labor, materials and equipment.

The estimated nuclear decommissioning cost described above is used for regulatory purposes. However, under GAAP requirements, the decommissioning cost estimate is calculated using a different method. As discussed above in Note 1 under Adoption of New Accounting Policies Accounting for Asset Retirement Obligations, on January 1, 2003 the Utility adopted SFAS No. 143, a GAAP requirement. Under SFAS No. 143, the Utility adjusts its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. In addition, the Utility records the Utility s total nuclear decommissioning obligation as an asset retirement obligation (previously recorded in accumulated depreciation and decommissioning) on the Utility s Consolidated Balance Sheet. The total nuclear decommissioning obligation accrued in accordance with GAAP was approximately $1.1 billion at December 31, 2003 and $1.3 billion at December 31, 2002.

F-35

The CPUC has established the Nuclear Decommissioning Costs Triennial Proceeding to determine the Utility s estimated decommissioning costs and to establish the associated annual revenue requirement and escalation factors for consecutive three-year periods. In October 2003, the CPUC issued a decision in the 2002 Nuclear Decommissioning Costs Triennial Proceeding (covering 2003 through 2005) finding that the funds in the Diablo Canyon nuclear decommissioning trusts are sufficient to pay for the Diablo Canyon power plant s eventual decommissioning. The decision also set the annual decommissioning fund revenue requirement for Humboldt Bay Unit 3 at approximately $18.5 million and granted the Utility s request to begin decommissioning Humboldt Bay Unit 3 in 2006 instead of 2015. The decision further granted the Utility s request of approximately $8.3 million for Humboldt Bay Unit 3 SAFSTOR operating and maintenance costs, with escalation adjustments of approximately $218,000 in 2004 and $230,000 in 2005. SAFSTOR 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 total adopted annual revenue requirement of approximately $26.7 million represents a decrease of approximately $4.5 million from the previously adopted revenue requirement of approximately $31.2 million which included amounts for both Humboldt Bay Unit 3 and Diablo Canyon. The CPUC also ordered the Utility to partially fund its 2004 revenue requirement with approximately $10 million that the Utility collected in rates in 2000 for its nuclear decommissioning revenue requirement, but that the Utility did not contribute to the trusts due to the Utility s cash conservation needs during the energy crisis.

The Utility s revenue requirements for nuclear decommissioning costs are recovered from ratepayers through a non-bypassable charge that will continue until those costs are fully recovered. Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. The Utility has three decommissioning trusts for its Diablo Canyon and Humboldt Bay Unit 3 nuclear facilities. The Utility has elected that two of these trusts be treated under the Internal Revenue Code as qualified trusts. If certain conditions are met, the Utility is allowed a deduction for the payments made to the qualified trusts. These payments cannot exceed the amount collected from ratepayers through the decommissioning charge. The qualified trusts are subject to a lower tax rate on income and capital gains, thereby increasing the trusts after-tax returns. Among other requirements, to maintain the qualified trust status the IRS must approve the amount to be contributed to the qualified trusts for any taxable year. The remaining non-qualified trust is exclusively for decommissioning Humboldt Bay Unit 3. The Utility cannot deduct amounts contributed to the non-qualified trust until such decommissioning costs are actually incurred.

In 2003, the Utility collected approximately $22.6 million in rates and contributed approximately $21.3 million, on an after-tax basis, to the nuclear decommissioning trusts. For 2004, the Utility is authorized to collect approximately $18.5 million in rates for decommissioning Humboldt Bay Unit 3. Of this amount, the Utility expects to contribute approximately $13.3 million, on an after-tax basis, to the qualified and non-qualified trusts for Humboldt Bay Unit 3. The Utility has requested the IRS approve the new amounts to be contributed to the qualified trusts for Humboldt Bay Unit 3. If the IRS does not approve the request, the Utility must withdraw any contributions it made to the qualified trusts for 2003 and contribute the withdrawn amounts, on an after-tax basis, to the non-qualified trust. The Utility would likely request that the CPUC approve an increase in revenue requirements to make up for the reduced amount contributed to the non-qualified trust due to the reduced rate of return attributable to taxes.

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

The Utility estimates after-tax annual earnings, including realized gains and losses, in the qualified trusts to range from 4.16% to 6.69% and in the non-qualified trusts to range from 3.79% to 5.97%. Annual returns decrease in later years as higher portions of the trusts are dedicated to fixed income investments leading up to and during the entire course of decommissioning activities.

All earnings on the assets held in the trusts, net of authorized disbursements from the trusts and investment management and administrative fees, are reinvested. Amounts may not be released from the decommissioning trusts until authorized by the CPUC. At December 31, 2003, the Utility had accumulated nuclear decommissioning trust funds with an estimated fair value of approximately $1.4 billion, based on quoted market prices and net of deferred taxes on unrealized gains.

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

The Utility accounts for its investments held in trusts as assets held for sale in accordance with SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities. Realized gains and losses are recognized as additions or reductions to trust asset balances. Unrealized gains and losses are recorded in regulatory asset or liability accounts in accordance with SFAS No. 71.

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

(in millions)	Maturity date	Total unrealized gains	Total unrealized losses	Fair value
Year ended December 31, 2003				
U.S. government and agency issues	2004-2032	$ 47	$	$ 586
Municipal bonds and other	2004-2034	11		147
Equity securities		409	(1)	790
Total		$467	$ (1)	$1,523
Year ended December 31, 2002				
U.S. government and agency issues	2004-2032	$ 50	$	$ 473
Municipal bonds and other	2004-2034	12	(1)	196
Equity securities		281	(9)	666
Total		$343	$(10)	$1,335

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

	Year ended December 31,		
(in millions)	2003	2002	2001
Proceeds received from sales of securities	$1,087	$1,631	$751
Gross realized gains on sales of securities held as available-for-sale	27	51	71
Gross realized losses on sales of securities held as available-for-sale	(44)	(91)	(98)

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy, or DOE, is responsible for the permanent storage and disposal of spent nuclear fuel. The Utility has signed a contract with the DOE to provide for the disposal of spent nuclear fuel and high-level radioactive waste from the Utility s nuclear power facilities. The DOE has been unable to meet its contractual commitment to begin accepting spent fuel. The

DOE s current estimate for an available site to begin accepting physical possession of the spent nuclear fuel is 2010. However, considerable uncertainty exists regarding when the DOE will begin to accept spent fuel for storage or disposal. Under the Utility s contract with the DOE, if the DOE completes a storage facility by 2010, the earliest Diablo

Canyon s spent fuel would be accepted for storage or disposal would be 2018. At the projected level of operation for Diablo Canyon, the Utility 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, the Utility has applied to the NRC for authorization to store spent fuel in an on-site dry cask storage facility. The NRC has provided initial approval for the facility and is expected to complete its authorization process in early 2004. The Utility has also initiated the process to obtain the required California Coastal Commission permit for this facility. If the dry cask storage facility is not approved or is delayed, the Utility also is pursuing NRC approval of another storage option to install a temporary rack in each unit that would increase the on-site storage capability to permit the Utility to operate Unit 1 until 2010 and Unit 2 until 2011. During this additional period of time, the Utility also would pursue NRC approval for a high density reracking of both units, which, if approved, would allow the Utility to operate both units until shortly before the licenses expire in 2021 for Unit 1 and 2024 for Unit 2. If the Utility is unsuccessful in permitting and constructing the on-site dry cask storage facility, and is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted until such time as spent fuel can be safely stored.

NOTE 9: EMPLOYEE BENEFIT PLANS

The Utility provides non-contributory defined benefit pension plans for its and certain affiliates employees and retirees (referred to collectively as pension benefits). The Utility has elected that certain of the trusts underlying these plans be treated under the Internal Revenue Code as qualified trusts. If certain conditions are met, the Utility is allowed a deduction for payments made to the qualified trusts, subject to certain Internal Revenue Code limitations. The Utility also provides contributory defined benefit medical plans for certain retired employees and their eligible dependents, and non-contributory defined benefit life insurance plans for certain retired employees (referred to collectively as other benefits). The following schedules aggregate all the Utility s plans. The Utility and its affiliates use a December 31 measurement date for all of its plans.

Benefit Obligations

The following reconciles changes in aggregate projected benefit obligations for pension benefits and changes in the benefit obligation of other benefits during 2003 and 2002:

Pension Benefits

(in millions)	2003	2002
Projected benefit obligation at January 1	$(6,732)	$(6,047)
Service cost for benefits earned	(170)	(138)
Interest cost	(445)	(435)
Plan amendments	(135)	
Actuarial loss	(338)	(409)
Settlement	4	1
Benefits and expenses paid	307	296
Projected benefit obligation at December 31	$(7,509)	$(6,732)
Accumulated benefit obligation	$(6,650)	$(6,085)

PG&E Corporation has participants in the Utility s Retirement Plan, Retirement Excess Benefit Plan and the Supplemental Executive Retirement Plan. PG&E Corporation s obligation for its participants in these plans was approximately $15 million at December 31, 2003 and $10 million at December 31, 2002.

Other Benefits

(in millions)	2003	2002
Benefit obligation at January 1	$(1,197)	$(1,046)
Service cost for benefits earned	(29)	(25)
Interest cost	(79)	(76)
Actuarial loss	(61)	(99)
Participants paid benefits	(33)	(25)
Plan amendments	(124)	
Benefits and expenses paid	79	74
Benefit obligation at December 31	$(1,444)	$(1,197)

PG&E Corporation has participants in the Utility s Postretirement Medical Plan and Postretirement Life Insurance Plan. PG&E Corporation s obligation for its participants in these plans was approximately $1 million at December 31, 2003 and $1 million at December 31, 2002.

Change in Plan Assets

The Utility uses publicly quoted market values and independent pricing services depending on the nature of the assets, as reported by the trustee to determine the fair value of the plan assets.

The following reconciles aggregate changes in plan assets during 2003 and 2002:

Pension Benefits

(in millions)	2003	2002
Fair value of plan assets at January 1	$6,153	$7,132
Actual return on plan assets	1,280	(686)
Company contributions	7	11
Settlement	(4)	(8)
Benefits and expenses paid	(307)	(296)
Fair value of plan assets at December 31	$7,129	$6,153

Other Benefits

(in millions)	2003	2002
Fair value of plan assets at January 1	$749	$ 899
Actual return on plan assets	186	(146)
Company contributions	72	48
Plan participant contributions	33	25
Benefits and expenses paid	(85)	(77)
Fair value of plan assets at December 31	$955	$ 749

F-39

Funded Status

The following schedule reconciles the plans aggregate funded status to the prepaid or accrued benefit cost recorded on the Utility s Consolidated Balance Sheets. The funded status is the difference between the fair value of plan assets and projected benefit obligations.

Pension Benefits

	December 31,	
(in millions)	**2003**	**2002**
Fair value of plan assets at December 31	$ 7,129	$ 6,153
Projected benefit obligation at December 31	(7,509)	(6,732)
Funded status plan assets less than projected benefit obligation	(380)	(579)
Unrecognized prior service cost	405	312
Unrecognized net loss	714	1,196
Unrecognized net transition obligation	8	22
Prepaid (accrued) benefit cost	$ 747	$ 951
Prepaid benefit cost	$792	$993
Accrued benefit liability	(45)	(42)
Additional minimum liability	(7)	(2)
Intangible asset		2
Accumulated other comprehensive income	7	
Prepaid (accrued) benefit cost	$747	$951

Other Benefits

	December 31,	
(in millions)	**2003**	**2002**
Fair value of plan assets at December 31	$ 955	$ 749
Benefit obligation at December 31	(1,444)	(1,197)
Funded status plan assets less than benefit obligation	(489)	(448)
Unrecognized prior service cost	125	13
Unrecognized net loss	125	174
Unrecognized net transition obligation	232	257
Prepaid (accrued) benefit cost	$ (7)	$ (4)
Prepaid benefit cost	$	$
Accrued benefit liability	(7)	(7)
Additional minimum liability		3

Prepaid (accrued) benefit cost	$ (7)	$ (4)

The prepaid benefit costs and accrued benefit liabilities of the Utility s pension and other benefit plans were as follows:

	December 31,	
(in millions)	2003	2002
Pension Benefits:		
Prepaid benefit cost	$792	$993
Accrued benefit liabilities	(45)	(42)
Other Benefits:		
Accrued benefit liabilities	$ (7)	$ (7)

The aggregate projected benefit obligation, accumulated benefit obligation and fair value of plan assets for plans in which the fair value of plan assets are less than either the projected benefit obligation or accumulated benefit obligation were as follows:

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
(in millions)	2003	2002	2003	2002
Utility:				
Projected benefit obligation	$(7,509)	$(6,732)	$(1,444)	$(1,197)
Accumulated benefit obligation	(6,650)	(6,085)		
Fair value of plan assets	7,129	6,153	955	749

Components of Net Periodic Benefit Cost

Pension Benefits

	December 31,		
(in millions)	2003	2002	2001
Service cost for benefits earned	$ 170	$ 138	$ 127
Interest cost	445	435	417
Expected return on Plan s assets	(507)	(592)	(641)
Amortized prior service cost	56	59	55
Amortization of unrecognized loss	46	(3)	(82)
Settlement loss	1	5	
Net periodic benefit cost (income)	$ 211	$ 42	$(124)

Other Benefits

	December 31,		
(in millions)	2003	2002	2001
Service cost for benefits earned	$ 29	$ 24	$ 21

Interest cost	79	76	73
Expected return on Plan s assets	(61)	(75)	(82)
Amortized prior service cost	28	28	28
Amortization of unrecognized loss	1	(4)	(21)
Net periodic benefit cost	$ 76	$ 49	$ 19

Valuation Assumptions

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

	Pension Benefits			Other Benefits		
	December 31,			December 31,		
	2003	2002	2001	2003	2002	2001
Discount rate	6.25%	6.75%	7.25%	6.25%	6.75%	7.25%
Average rate of future compensation increases	5.00%	5.00%	5.00%			
Expected return on plan assets						
Pension Benefits	8.10%	8.10%	8.50%			
Other Benefits:						
Defined Benefit Medical Plan Bargaining				8.50%	8.50%	8.50%
Defined Benefit Medical Plan Management				7.60%	7.20%	8.50%
Defined Benefit Life Insurance Plan				8.50%	8.10%	8.50%

The assumed health care cost trend rate for 2004 is approximately 9.5%, grading down to an ultimate rate in 2008 and beyond of approximately 5.5%. A one-percentage point change in assumed health care cost trend rate would have the following effects:

	One-Percentage Point Increase	One-Percentage Point Decrease
Effect on postretirement benefit obligation	$ 31	$ (28)
Effect on service and interest cost	3	(2)

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed income projected returns were based on historical returns for the broad U.S. bond market. Equity returns were based primarily on historical returns of the S&P 500 Index. For the Utility Retirement Plan, the assumed return of 8.1% compares to a ten-year actual return of 8.5%.

The difference between actual and expected return on plan assets is included in net amortization and deferral, and is considered in the determination of future net benefit income (cost). The actual return on plan assets was above the expected return in 2003, and below the expected return for 2002 and 2001.

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

Asset Allocations

The asset allocation of the Utility s pension and other benefit plans at December 31, 2003 and 2002, and target 2004 allocation was as follows:

	Pension Benefits			Other Benefits		
	2004	2003	2002	2004	2003	2002
Equity Securities						
U.S. Equity	40%	42%	39%	51%	50%	49%
Non-U.S. Equity	20	22	20	20	22	20
Debt Securities	40	36	41	29	28	31
Total	100%	100%	100%	100%	100%	100%

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

The maturity of debt securities at December 31, 2003 and 2002 ranges from 1 to 46 years, with a weighted average maturity of 7 years.

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

A benchmark portfolio for each asset class is set based on market capitalization and valuations of equities and the durations and credit quality of debt securities. Investment managers for each asset class are retained to periodically adjust, or actively manage, the combined portfolio against the benchmark. Active management covers approximately 50% of the U.S. equity, 80% of the non-U.S. equity and virtually 100% of the debt security portfolios.

Cash Flow Information

The Utility expects to contribute up to $129 million to its Pension Benefits Plan, assuming favorable resolution of pension related rate recovery in the 2003 GRC, and approximately $65 million to its Other Benefits Plan in 2004. These contributions would be consistent with the Utility s funding policy, which is to contribute amounts that are tax deductible, consistent with applicable regulatory decisions and sufficient to meet minimum funding requirements. None of these benefit plans are subject to a minimum funding requirement in 2004.

Defined Contribution Pension Plan

PG&E Corporation and the Utility also sponsor defined contribution pension plans. 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 of up to 4.5% of an employee s base compensation. Matching employer contributions are automatically invested in PG&E Corporation common stock. Employees may reallocate matching employer contributions and accumulated earnings thereon to another investment fund or funds available to the plan at any time once they have been credited to their account. Employer contribution expense reflected in the Utility s Consolidated Statements of Operations amounted to $37 million in 2003, $36 million in 2002 and $33 million in 2001.

Long-Term Incentive Program

PG&E Corporation maintains a long-term incentive program, or LTIP, that permits stock options, restricted stock and other stock-based incentive awards to be granted to non-employee directors, executive officers and other employees of the Utility. Stock options can be granted with or without associated stock appreciation rights and dividend equivalents.

Stock Options

The weighted average grant date fair values of options to purchase PG&E Corporation common stock granted using the Black-Scholes valuation method were $7.27 per share in 2003, $6.60 per share in 2002, and $6.01 and $5.80 per share in 2001, using two sets of assumptions. Significant assumptions used in the Black-Scholes valuation method for shares granted in 2003, 2002, and 2001 (two sets of assumptions) were:

	2003	2002	2001
Expected stock price volatility	45.00%	30.00%	33.00% & 29.05%
Expected dividend yield	0.00%	0.00%	0.00% & 4.35%
Risk-free interest rate	3.46%	4.65%	5.24% & 5.95%
Expected life	6.5 years	10 years	10 years

Stock options issued after January 2003 become exercisable on a cumulative basis at one-fourth each year commencing one year from the date of the grant. Stock options issued before January 2003 become exercisable on a cumulative basis at one-third each year commencing two years from the date of grant. All options expire ten years and one day after the date of grant. Stock options outstanding to purchase PG&E Corporation common stock held by Utility employees at December 31, 2003 had option prices ranging from $12.63 to $34.25, and a weighted average remaining contractual life of 6.19 years. The following table summarizes the stock option activity for the Utility employees for the years ended December 31:

	2003		2002		2001	
	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
Outstanding at January 1	13,300,300	$22.32	13,601,834	$22.35	9,414,899	$26.68
Granted	2,160,425	14.62			4,404,700	14.32
Exercised	(1,310,156)	20.97	(187,935)	23.49	(129,999)	31.96
Cancelled	(607,387)	27.05	(113,599)	23.98	(87,766)	26.70
Outstanding at December 31	13,543,182	21.01	13,300,300	22.32	13,601,834	22.35
Exercisable	7,668,908	25.33	6,314,620	27.72	4,236,566	28.79

The following summarizes information for options outstanding and exercisable at December 31, 2003. Of the outstanding options at December 31, 2003:

5,995,290 options had exercise prices ranging from $12.63 to $16.68, with a weighted average remaining contractual life of 7.93 years, of which 1,113,239 options were exercisable at a weighted average exercise price of $14.41;

3,210,388 options had exercise prices ranging from $19.81 to $26.31, with a weighted average remaining contractual life of 5.46 years, of which 2,218,165 options were exercisable at a weighted average exercise price of $20.52; and

4,337,504 options had exercise prices ranging from $28.35 to $34.25, with a weighted average remaining contractual life of 4.33 years, of which 4,337,504 options were exercisable at a weighted average exercise price of $30.59.

In addition, 1,638,500 options were granted to Utility employees on January 2, 2004 at an exercise price of $27.23, the then-current market price of PG&E Corporation common stock.

Restricted Stock

On January 2, 2003, a total of 934,630 shares of restricted PG&E Corporation common stock were awarded to eligible Utility employees. The shares were granted with restrictions and are subject to forfeiture unless certain conditions are met.

The restricted shares are held in an escrow account. The shares become available to the employees as the restrictions lapse. For restricted stock granted in 2003, the restrictions on 80% of the shares lapse automatically over a period of four years at the rate of 20% per year. The compensation expense for these shares remains fixed at the value of the stock at grant date. Restrictions on the remaining 20% of the shares will lapse at a rate of 5% per year if PG&E Corporation is in the top quartile of its comparator group, as measured by annual total shareholder return for each year ending immediately before each annual lapse date. The compensation expense recognized for these shares is variable and changes with the common stock s market price.

Compensation expense associated with all the shares is recognized on a quarterly basis. Total compensation expense resulting from the restricted stock issuance reflected on the Utility s Consolidated Statements of Operations was approximately $4.4 million in 2003. On January 2, 2004, PG&E Corporation awarded 333,110 shares of restricted stock, to Utility employees. For restricted stock grants awarded in 2004, the restrictions lapse ratably over four years.

Performance Units and Performance Shares

PG&E Corporation has granted performance units to certain officers and employees of the Utility. The performance units, subject to the achievement of certain performance targets, vest one-third per year and are settled in cash annually as vesting occurs in each of the three years following the year of grant. The number of performance units held by Utility employees that were outstanding at December 31, 2003 was 123,280. The amount of compensation expense recognized in connection with the issuance of performance units was approximately $3,595,541 million in 2003. The amount of compensation expense recognized in 2002 and 2001 was not material. No performance units were granted in 2004.

On January 2, 2004, PG&E Corporation awarded 333,110 performance shares, or phantom stock, to Utility employees. The performance shares, subject to the achievement of certain performance targets, vest one-third per year and will be settled annually as vesting occurs in each of the three years following the date of the grant.

PG&E Corporation Supplemental Retirement Savings Plan

The supplemental retirement savings plan of PG&E Corporation provides supplemental retirement alternatives to eligible officers and key employees of the Utility by allowing participants to defer portions of their compensation, including salaries and amounts awarded under various incentive awards, and to receive supplemental employer-provided retirement benefits. Under the employee-elected deferral component of the plan, eligible employees may defer all or part of their incentive awards, and 5% to 50% of their salary. Under the supplemental employer-provided retirement benefits component of the plan, eligible employees may receive full credit for employer matching and basic contributions, under the respective defined contribution plan, in excess of limitations set out by the Internal Revenue Code. A separate non-qualified account is maintained for each eligible employee to track deferred amounts. The account s value is adjusted in accordance with the performance of the investment options selected by the employee. PG&E Corporation and the Utility adjust each employee s account on a quarterly basis and record additional compensation expense or income in the Utility s financial statements. Total compensation expense recognized by the Utility in connection with the plan amounted to approximately $1 million for the year ended December 31, 2003. For the year ended December 31, 2002 and 2001 the compensation expense recognized in connection with the plan was not material.

Retention Programs

PG&E Corporation implemented various retention programs in 2001. One of these programs granted key personnel of the Utility with lump-sum cash payments. In addition, another program granted units of special senior executive retention grants.

These grants provided certain employees with PG&E Corporation phantom restricted stock units that vested in full on December 31, 2003 upon PG&E Corporation meeting certain performance measures at that date. A total of 879,611 phantom stock units were granted to employers of the Utility under this program. These units were marked to market based on the market price of PG&E Corporation common stock and amortized as a charge to income over a four-year period. As a result of meeting the performance criteria at December 31, 2003 these units fully vested and the remaining compensation expense was recognized in 2003. Total compensation expense recognized in connection with these retention mechanisms, including cash payments and phantom restricted stock units, amounted to $38 million in 2003, $7 million in 2002 and $26 million in 2001.

In January 2004, PG&E Corporation paid amounts due under the senior executive retention program to participating individuals. There are no payments remaining under either plan.

NOTE 10: INCOME TAXES

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

	Year Ended December 31,		
(in millions)	2003	2002	2001
Current	$ 695	$ 838	$ 902
Deferred	(150)	351	(267)
Tax credits, net	(17)	(11)	(39)
Income tax expense	$ 528	$1,178	$ 596

The following describes net deferred income tax liabilities:

	Year Ended December 31,	
(in millions)	2003	2002
Deferred Income Tax Assets:		
Customer advances for construction	$ 386	$ 318
Unamortized investment tax credits	110	105
Reserve for damages	273	268
Environmental reserve	172	162
Other	252	79
Total deferred income tax assets	$1,193	$ 932
Deferred Income Tax Liabilities:		
Regulatory balancing accounts	$ 139	$ 175
Property related basis differences	2,005	1,778
Income tax regulatory asset	142	134
Other	327	325
Total deferred income tax liabilities	2,613	2,412
Total net deferred income taxes liabilities	$1,420	$1,480
Classification of Net Deferred Income Taxes Liabilities:		
Included in current liabilities	$ 86	$ (5)
Included in noncurrent liabilities	1,334	1,485

Total net deferred income taxes liabilities	$1,420	$1,480

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,		
	2003	2002	2001
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)	4.9	5.4	5.0
Effect of regulatory treatment of depreciation differences	(2.5)	1.1	1.7
Tax credits, net	(1.5)	(0.5)	(2.5)
Other, net	0.5	(1.7)	(2.2)
Effective tax rate	36.4%	39.3%	37.0%

At December 31, 2003, the Utility had $794 million of California net operating loss, or 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, 2003 and December 31, 2002.

NOTE 11: COMMITMENTS AND CONTINGENCIES

The Utility has substantial financial commitments and contingencies in connection with agreements entered into supporting its operating activities.

Commitments

Power Purchase Agreements

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

As a result of the energy crisis, the Utility owed approximately $1 billion to qualifying facilities when it filed its Chapter 11 petition. Through December 31, 2003, the principal payments made to the qualifying facilities amounted to $998 million.

At December 31, 2003, the Utility had agreements with 300 qualifying facilities for approximately 4,400 megawatts, or MW, that are in operation. Agreements for approximately 4,000 megawatts expire between 2004 and 2028. Qualifying facility power purchase agreements for approximately 400 MW have no specific expiration dates and will terminate only when the owner of the qualifying facility exercises its termination option. The Utility also has agreements with 50 qualifying facilities that are not currently providing or expected to provide electricity. The total of approximately 4,400 MW consists of approximately 2,600 MW from cogeneration projects, 800 MW from wind projects and 1,000 MW from other projects, including biomass, waste-to-energy, geothermal, solar and hydroelectric. On January 22, 2004, the CPUC adopted a decision that requires California investor-owned electric utilities to allow owners of qualifying facilities with power purchase agreements expiring before the end of 2005 to extend these contracts for five years. Qualifying facility power purchase agreements accounted for approximately 20% of the Utility s 2003 electricity sources, approximately 25% of the Utility s 2002 electricity sources, and approximately 21% of the Utility s 2001 electricity resources. No single qualifying facility accounted for more than 5% of the Utility s 2003, 2002 or 2001 electricity sources.

In a proceeding pending at the CPUC, the Utility has requested refunds in excess of $500 million for overpayments from June 2000 through March 2001 made to qualifying facilities. Under the Settlement Agreement, the net after-tax amount of any qualifying facilities refunds, which the Utility actually realizes in cash, claim offsets or other credits, would reduce the $2.21 billion after-tax regulatory asset. While the Utility is unable to estimate the outcome of this proceeding they believe the proceeding will not have a material adverse effect on their financial condition or results of operations.

Irrigation Districts and Water Agencies The Utility has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments based on the irrigation districts and water agencies debt service requirements, regardless if any hydroelectric power is supplied, and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. The Utility s irrigation district and water agency contracts accounted for approximately 5% of 2003 electricity sources, approximately 4% of 2002 electricity sources and approximately 3% of 2001 electricity sources.

Other Power Purchase Agreements

Electricity Purchases to Satisfy the Residual Net Open Position On January 1, 2003, the Utility resumed buying electricity to meet its residual net open position. During that year, more than 14,000 GWh of energy was bought and sold in the wholesale market to manage the 2003 residual net open position. Most of the Utility s contracts entered into in 2003 had terms of less than one year. During 2004 the Utility plans to enter into contracts of longer duration to satisfy its near-term residual net open position.

Renewable Energy Requirement California law requires that, beginning in 2003, each California investor-owned electric utility must increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2017. The Utility estimates the annual procurement target will initially require it to purchase about 750 Gigawatt-hours, or GWh, of electricity from renewable resources each year. The Utility met its 2003 commitment and the CPUC has approved several contracts intended to meet its 2004 renewable energy requirement.

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 2001 through 2003 were as follows:

	2003	2002	2001
Gigawatt hours received	33,431	28,088	23,732
Qualifying facility energy payments (in millions)	$ 994	$ 1,051	$ 1,454
Qualifying facility capacity payments (in millions)	499	506	473
Irrigation district and water agency payments (in millions)	62	57	54
Other power purchase agreement payments (in millions)	513	196	155

At December 31, 2003, the undiscounted future expected power purchase agreement payments were as follows:

	Qualifying Facility		Irrigation District & Water Agency		Other		
(in millions)	Energy	Capacity	Operations & Maintenance	Debt Service	Energy	Capacity	Total
2004	$ 1,070	$ 520	$ 41	$ 28	$ 60	$ 36	$ 1,755
2005	1,040	520	35	26	27	36	1,684
2006	1,020	510	31	26	27	36	1,650
2007	970	490	30	26	28	35	1,579
2008	940	480	31	26	14	8	1,499
Thereafter	8,300	4,100	182	142	79	49	12,852
Total	$13,340	$6,620	$350	$274	$235	$200	$21,019

Natural Gas Supply and Transportation Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers. The contract lengths and natural gas sources of the Utility s portfolio of natural gas procurement contracts has fluctuated, generally based on market conditions.

As a result of the Utility s Chapter 11 filing and its credit rating being below investment grade, it uses several different credit arrangements to purchase natural gas, including a $10 million cash collateralized standby letter of credit and a pledge of its core natural gas customer accounts receivable. The core natural gas inventory also may be pledged, but only if the amount of the Utility s natural gas customer accounts receivable is less than the amount that it owes to natural gas suppliers. To date, the Utility s accounts receivable pledge has been sufficient. The pledged amounts were approximately $561 million at December 31, 2003 and $513 million at December 31, 2002. It is anticipated that the pledge of natural gas customer accounts receivable and natural gas inventory will be replaced with letters of credit no later than the effective date of the Plan of Reorganization.

The Utility also has long-term gas transportation service agreements with various Canadian and interstate pipeline companies. These companies are responsible for transporting the Utility s gas to the California border. These agreements include provisions for payment of fixed demand charges for reserving firm pipeline capacity as well as volumetric transportation charges. The total demand charges that the Utility will pay each year may change periodically as a result of changes in regulated tariff rates. The total demand (net of sales of excess supplies) and volumetric transportation charges the Utility incurred under these agreements were approximately $131 million in 2003, $101 million in 2002 and $239 million in 2001.

At December 31, 2003, the Utility s obligations for natural gas purchases and gas transportation services were as follows:

(in millions)	
2004	$ 852
2005	115
2006	26
2007	7
2008	
Thereafter	
Total	$1,000

Nuclear Fuel Agreements

The Utility has purchase agreements for nuclear fuel. These agreements have terms ranging from two to five years and are intended to ensure long-term fuel supply. Deliveries under nine of the eleven contracts in place at the end of 2003 will end by 2005. In most cases, the Utility s nuclear fuel contracts are requirements-based. The Utility relies on large, well-established international producers of nuclear fuel in order to diversify its commitments and provide security of supply. Pricing terms are also diversified, ranging from fixed prices to base prices that are adjusted using published information.

At December 31, 2003, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)	
2004	$ 90
2005	12
2006	13
2007	14
2008	13
Thereafter	52
Total	$ 194

Payments for nuclear fuel amounted to approximately $57 million in 2003, $70 million in 2002 and $50 million in 2001.

WAPA Commitments

In 1967, the Utility and the Western Area Power Administration, or WAPA, entered into several long-term power contracts governing the interconnection of the Utility s and WAPA s electricity transmission systems, the use of the Utility s electricity transmission and distribution system by WAPA, and the integration of the Utility s and WAPA s customer demands and electricity resources. The contracts give the Utility access to WAPA s excess hydroelectric power and obligate the Utility to provide WAPA with electricity when its own resources are not sufficient to meet its requirements. The contracts are scheduled to terminate on December 31, 2004, but termination is subject to FERC approval, which the Utility expects to receive.

The costs to fulfill the Utility s obligations to WAPA under the contracts cannot be accurately estimated at this time since both the purchase price and the amount of electricity WAPA will need from the Utility in 2004 are uncertain. However, the Utility expects that the cost of meeting its contractual obligations to WAPA will be greater than the price the Utility receives from WAPA under the contracts. Although it is not indicative of future sales commitments or sales-related costs, WAPA s net amount purchased from the Utility was approximately 4,804 GWh, in 2003, 3,619 GWh in 2002 and 4,823 GWh in 2001.

Transmission Control Agreement

The Utility is a party to a Transmission Control Agreement, or TCA, with the ISO and other participating transmission owners. As a transmission owner, the Utility is required to give two years notice and receive regulatory approval if it wishes to withdraw from the TCA. Under this agreement, the transmission owners, which also include Southern California Edison, or SCE, San Diego Gas & Electric Company and several municipal utilities, assign operational control of their electricity transmission systems to the ISO. In addition, as a party to the TCA, the Utility is responsible for a share of the costs of reliability must-run, or RMR, agreements between the ISO and owners of the power plants subject to RMR agreements, or RMR Plants. The Utility also is an owner of some of these RMR Plants for which the Utility receives revenue from the ISO. Under the RMR agreements, RMR Plants must remain available to generate electricity when needed for local transmission system reliability upon the ISO s demand.

At December 31, 2003, the ISO had RMR agreements for which the Utility could be obligated to pay the ISO an estimated $446 million in net costs during the period January 1, 2004 to December 31, 2005. These costs are recoverable under applicable ratemaking mechanisms.

It is possible that the Utility may receive a refund of RMR costs that the Utility 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 Corporation, or Mirant, that are parties to three RMR agreements with the ISO to refund to the ISO, and the ISO to refund to the Utility, excess payments of approximately $340 million, including interest, for availability of Mirant s RMR Plants under these agreements. However, on July 14, 2003, Mirant filed a petition for reorganization under Chapter 11 and on December 15, 2003, the Utility filed claims in Mirant s Chapter 11 proceeding including a claim for an RMR refund. The Utility is 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. It is uncertain how the resolution of this matter would be reflected in rates.

Other Commitments

The Utility has other commitments relating to operating leases, capital infusion agreements, equipment replacements, software licenses, the self-generation incentive program exchange agreements and telecommunication contracts. At December 31, 2003, the future minimum payments related to other commitments were as follows:

	(in millions)
2004	$126
2005	48
2006	30
2007	15
2008	14
Thereafter	5
Total	$238

Contingencies

Utility

2003 General Rate Case Settlement and Generation Settlement

The CPUC determines the amount of authorized base revenues the Utility can collect from customers to recover its basic business and operational costs for electricity and natural gas distribution operations and for electricity generation operations in a GRC. The Utility s last GRC was its 1999 GRC, approved by the CPUC in 2000. The 2003 GRC has been filed, testimony has been given before the CPUC and the Utility is awaiting a final decision. Any revenue requirement change resulting from a final decision will be retroactive to January 1, 2003.

In July 2003, the Utility and various intervenors (The CPUC s Office of Ratepayer Advocates, or ORA, TURN, Aglet Consumer Alliance, and the City and County of San Francisco) filed a joint motion with the CPUC seeking approval of a settlement agreement resolving specific issues related to the cost of operating the Utility s electricity generation facilities, or the generation settlement. In September 2003, the Utility and various intervenors (ORA, TURN, Aglet Consumer Alliance, the Modesto Irrigation District, the Natural Resources Defense Council and the Agricultural Energy Consumers Association) filed a joint motion with the CPUC seeking approval of the GRC settlement. The GRC settlement, together with the generation settlement, resolves all disputed economic issues among the settling parties related to the Utility s electricity distribution, natural gas distribution, and generation revenue requirements, with the exception of the Utility s request that the CPUC include the costs of a pension contribution in the Utility s revenue requirement. The CPUC will resolve the pension contribution issue, as well as other issues raised by non-settling intervenors, in its final decision. The CPUC agreed in the Settlement Agreement to act promptly on the 2003 GRC.

The GRC settlement would result in a total 2003 revenue requirement of approximately $2.5 billion for electricity distribution operations, representing a $236 million increase in the Utility s electricity distribution revenue requirement over the current authorized amount. The GRC settlement provides that the electricity distribution rate base on which the Utility would be entitled to earn an authorized rate of return would be approximately $7.7 billion, based on recorded 2002 plant, and including net weighted average capital additions for 2003 of approximately $292 million.

The GRC settlement also would result in a total 2003 revenue requirement of approximately $927 million for the Utility s natural gas distribution operations, representing a approximately $52 million increase in the Utility s natural gas distribution revenue requirement over the current authorized amount. The GRC settlement also provides that the amount of natural gas distribution rate base on which the Utility 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 approximately $89 million.

Together with the generation settlement, the GRC settlement would result in a 2003 generation revenue requirement of approximately $912 million representing an increase of approximately $38 million in the Utility s generation revenue requirement over the current authorized amount. This generation revenue requirement excludes fuel expense, the cost of electricity purchases, the DWR revenue requirements and nuclear decommissioning revenue requirements. Under the Settlement Agreement, the Utility s adopted 2003 generation rate base of approximately $1.6 billion would be 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 the Utility s electricity generation rate base would allow recognition of an after-tax regulatory asset of approximately $800 million (or approximately $1.3 billion pre-tax) as estimated at December 31, 2003. The Utility expects to record this regulatory asset when it meets the probability requirements for regulatory recovery in rates as provided for in SFAS No. 71. The individual components of the regulatory asset will be amortized over their respective lives. The weighted average life of these individual components is approximately 16 years.

The GRC settlement also provides for new balancing accounts to be established retroactive to January 1, 2004, that permit the Utility to recover its authorized electricity distribution and generation revenue requirements regardless of the level of sales. If sales levels do not generate revenues equal to the full revenue requirement in a period, rates in subsequent periods will be increased to collect the shortfall. Similarly, future rates will decrease if sales levels generate more than the full revenue requirement.

If the Utility prevails on the pension contribution issue, an additional revenue requirement of approximately $75 million would be allocated among electricity distribution, natural gas distribution and electricity generation operations.

Because the CPUC has yet to issue a final decision on the Utility s 2003 GRC, the Utility has not included the natural gas distribution revenue requirement increase in its 2003 results of operations. If the CPUC approves a 2003 revenue requirement increase in 2004, the Utility would record both the 2003 and 2004 natural gas distribution revenue requirement increase in its 2004 results of operations.

In 2003 the Utility collected electricity revenue and surcharges subject to refund under the frozen rate structure. The amount of electricity revenue subject to refund pursuant to the rate design settlement in 2003 was $125 million, which incorporates the impact of the electric portion of the GRC settlement. The Utility has recorded a regulatory liability for such amount. If the revenue requirement that is ultimately approved in the Utility s 2003 GRC is lower than the amounts described above, the regulatory liability would increase.

The CPUC also is considering a proposed reliability performance incentive mechanism for the Utility that would be in effect from 2004 through 2009. Under the proposed incentive mechanism, the Utility would receive up to $27 million in additional annual revenues to be recorded in a one-way balancing account to be spent exclusively on reliability performance activities with a goal of decreasing the duration and frequency of electricity outages. The Utility would be entitled to earn a maximum reward of up to $42 million each year depending on the extent to which the Utility exceeded the reliability performance improvement targets.

Conversely, the Utility would be required to pay a penalty of up to $42 million a year depending on the extent to which it failed to meet the target.

On February 3, 2004, the CPUC reopened the 2003 GRC record for the purpose of taking further evidence regarding executive compensation and bonuses. The Utility has filed a report addressing these issues with the CPUC. The Utility is uncertain how this matter will be resolved and when a final GRC decision will be issued.

If the GRC settlement is not approved by the CPUC, the Utility s ability to earn its authorized rate of return for the years until the next GRC would be adversely affected. The parties to the GRC settlement have agreed that the Utility s next GRC will determine rates for test year 2007. The Utility is unable to predict the outcome of the 2003 GRC or the impact it will have on its financial condition or results of operations.

Surcharge Revenues

In January 2001, the CPUC authorized increases in electricity rates of $0.01 per kilowatt-hour, or kWh, in March 2001 of another $0.03 per kWh and in May 2001 of 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 the surcharges to be used to restore the Utility s financial health by permitting the Utility to record amounts related to the surcharge revenues as an offset to unrecovered transition costs. From January 2001 to December 31, 2003, the Utility recognized total surcharge revenues subject to refund of approximately $8.1 billion, pre-tax. The rate design settlement includes a refund of approximately $125 million of surcharge revenues. Accordingly, at December 31, 2003, the Utility had recorded a regulatory liability for potential refund of approximately $125 million of surcharge revenues collected in 2003. In addition, if the CPUC requires the Utility to refund any amounts in excess of $125 million, the Utility s earnings could be materially adversely affected.

PX Block-Forward Contracts

The Utility had PX block-forward contracts, which were seized by California then-Governor Gray Davis in February 2001 for the benefit of the state, acting under California s Emergency Services Act. The block-forward contracts had an estimated unrealized gain of up to $243 million at the time the state of California seized them. The Utility, the PX, and some of the PX market participants have filed claims in state court against the state of California to recover the value of the seized contracts; the state of California disputes the plaintiff s valuations. This state court litigation is pending.

FERC Prospective Price Mitigation Relief

Various entities, including the Utility and the State of California, are seeking up to $8.9 billion in refunds for electricity overcharges on behalf of California electricity purchasers from January 2000 to June 2001. In December 2002, a FERC administrative law judge issued an initial decision finding that power suppliers overcharged the utilities, the State of California and other buyers approximately $1.8 billion from October 2, 2000 to June 20, 2001 (the only time period for which the FERC permitted refund claims), but that California buyers still owe the power suppliers approximately $3.0 billion, leaving approximately $1.2 billion in net unpaid bills.

During 2003, the FERC confirmed most of the administrative law judge s findings, but partially modified the refund methodology to include use of a new natural gas price methodology as the basis for mitigated prices. The FERC indicated that it would consider later allowances claimed by sellers for natural gas costs above the natural gas prices in the refund methodology. In addition, the FERC directed the ISO and the PX, which operates solely to reconcile remaining refund amounts owed, to make compliance filings establishing refund amounts by March 2004. The ISO has indicated that it plans to make its compliance filing by August 2004. The actual refunds will not be determined until the FERC issues a final decision, following the ISO and PX compliance filings. The FERC is uncertain when it will issue a final decision in this proceeding. In addition, future refunds could increase or decrease as a result of an alternative calculation proposed by the ISO, which incorporates revised data provided by the Utility and other entities.

Under the Settlement Agreement, the Utility and PG&E Corporation 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 the Utility s ISO, PX, qualifying facilities or energy service provider costs that are actually realized in cash or by offset of creditor claims in its Chapter 11 proceeding would reduce the balance of the $2.21 billion after-tax regulatory asset created by the Settlement Agreement.

The Utility has recorded approximately $1.8 billion of claims filed by various electricity generators in its Chapter 11 proceeding as liabilities subject to compromise. This amount is subject to a pre-petition offset of approximately $200 million, reducing the net liability recorded to approximately $1.6 billion. The Utility currently estimates that the claims filed would have been reduced to approximately $1.2 billion based on the refund methodology recommended in the administrative law judge s initial decision, resulting in a net liability of approximately $1.0 billion after the approximately $200 million pre-petition offset. The recalculation of market prices according to the revised methodology adopted by the FERC in its October 2003 decision could further reduce the amount of the suppliers claims by several hundred million dollars. However this reduction could be offset by the amount of any additional fuel cost allowance for suppliers if they demonstrate that natural gas prices were higher than the natural gas prices assumed in the refund methodology.

Nuclear Insurance

The Utility has several types of nuclear insurance for its Diablo Canyon power plant and Humboldt Bay Unit 3. The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited, or NEIL. NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to $3.24 billion per incident. Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss causing a prolonged outage, the Utility may be required to pay 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, the Utility purchased the maximum available public liability insurance of $300 million for the Diablo Canyon power plant. The balance of the $10.9 billion of liability protection is covered by a loss-sharing program (secondary financial protection) among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of reactors 100 MW or higher. If a nuclear incident results in costs in excess of $300 million, then the Utility may be responsible for up to $100.6 million per reactor, with payments in each year limited to a maximum of $10 million per incident until the Utility has fully paid its share of the liability. Since the Diablo Canyon power plant has two nuclear reactors over 100 MW, the Utility may be assessed up to $201.2 million per incident, with payments in each year limited to a maximum of $20 million per incident. Although the Price-Anderson Act expired on December 31, 2003, coverage continues to be provided to all licensees, including the Diablo Canyon power plant, that had coverage before December 31, 2003. Congress may address renewal of the Price-Anderson Act in future energy legislation.

In addition, the Utility has $53.3 million of liability insurance for the retired nuclear generating unit at Humboldt Bay power plant and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of liability insurance.

Workers Compensation Security

The Utility is self-insured for workers compensation. The Utility must deposit collateral with the California Department of Industrial Relations, or DIR, to maintain its status as a self-insurer for workers compensation claims made against the Utility. Acceptable forms of collateral include surety bonds, letters of credit, cash and securities. At December 31, 2003, the Utility provided collateral in the form of $305 million in surety bonds and approximately $43 million in a cash deposit.

In February 2001, several surety companies provided cancellation notices because of the Utility s financial situation. The cancellation of these bonds has not impacted the Utility s self-insured status under California law. The DIR 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, toward the $348 million collateral requirement. At December 31, 2003, the Utility s $348 million in collateral consisted of the $185 million in cancelled bonds, $120 million in active surety bonds and approximately $43 million in cash. PG&E Corporation has guaranteed the Utility s reimbursement obligation associated with these surety bonds and the Utility s underlying obligation to pay workers compensation claims.

El Paso Settlement

In June 2003, the Utility, along with a number of other parties, 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, El Paso will pay approximately $1.5 billion in cash and non-cash consideration, of which approximately $550 million is now in an escrow account and approximately $875 million will be paid over 15 to 20 years. The Utility s share of the approximately $1.5 billion settlement is approximately $300 million. El Paso also agreed to a approximately $125 million reduction in El Paso s long-term electricity supply contracts with the DWR, to provide pipeline capacity to California and to ensure specific reserve capacity for the Utility, if needed. In October 2003, the CPUC approved an allocation of these refunds, under which the Utility s natural gas customers would receive approximately $80 million and its electricity customers would receive approximately $216 million. The settlement was approved by the FERC in November 2003 and by the San Diego Superior Court in December 2003. At least one appeal of the San Diego Superior Court s approval has been filed; however, the Utility believes that it is probable that the El Paso settlement will not be overturned on appeal.

Enron Settlement

On December 23, 2003, the Utility entered into a settlement agreement with five subsidiaries of Enron Corporation, or Enron, settling certain claims between the Utility and Enron, or the Enron settlement. The Enron settlement will become effective if approved by the bankruptcy courts overseeing both the Utility s and Enron s Chapter 11 proceedings. A hearing for approval of the Enron settlement is currently scheduled in the Utility s Chapter 11 proceeding on March 5, 2004. A hearing was held in the Enron bankruptcy court on February 5, 2004 and the matter was submitted. If the Enron settlement is approved, the Utility will receive an after-tax credit of approximately $90 million that will reduce the $2.21 billion after-tax regulatory asset as called for in the Settlement Agreement. In its January 26, 2004 filing with the CPUC proposing an electricity rate reduction, the Utility has reduced the revenue requirement related to the $2.21 billion after-tax regulatory asset to reflect this after-tax credit.

DWR Contracts

The DWR provided approximately 30% of the electricity delivered to the Utility s customers for the year ended December 31, 2003. The DWR purchased the electricity under contracts with various generators and through open market purchases. The Utility is responsible for administration and dispatch of the DWR s electricity procurement contracts allocated to the Utility, for purposes of meeting a portion of the Utility s net open position. The DWR remains legally and financially responsible for the electricity procurement contracts.

The contracts terminate at various times through 2012, and consist of must-take and capacity charge contracts. Under must-take contracts, the DWR must take and pay for electricity generated by the applicable generating facility regardless of whether the electricity is needed. Under capacity charge contracts, the DWR must pay a capacity charge but is not required to purchase electricity unless that electricity is dispatched and delivered.

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

- After assumption, the Utility s issuer rating by Moody s will be no less than A2 and the Utility s long-term issuer credit rating by S&P will be no less than A;
- The CPUC first makes a finding that the DWR power purchase contracts to be assumed are just and reasonable; and
- The CPUC has acted to ensure that the Utility will receive full and timely recovery in its retail electricity rates of all costs associated with the DWR power purchase contracts to be assumed without further review.

Environmental Matters

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

The cost of environmental remediation is difficult to estimate. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can estimate a range of reasonably likely clean-up costs. The Utility reviews its remediation liability on a quarterly basis for each site where it may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure using current technology, enacted laws and regulations, experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the costs at the lower end of this range. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning the Utility s responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. The Utility estimates the upper end of the cost range using reasonably possible outcomes least favorable to the Utility.

The Utility had an undiscounted environmental remediation liability of approximately $314 million at December 31, 2003 and approximately $331 million at December 31, 2002. During 2003, the liability was reduced by approximately $17 million mainly due to reassessment of the estimated cost of remediation and remediation payments. The approximately $314 million accrued at December 31, 2003 includes approximately $104 million related to the pre-closing remediation liability associated with divested generation facilities and approximately $210 million related to remediation costs for those generation facilities that the Utility still owns, gas gathering sites, compressor stations, third party disposal sites and manufactured gas plant sites that either are owned by the Utility or are the subject of remediation orders by environmental agencies or claims by the current owners of the former manufactured gas plant sites. Of the approximately $314 million environmental remediation liability, approximately $147 million has been included in prior rate setting proceedings and the Utility expects that approximately $116 million will be allowable for inclusion in future rates. The Utility also recovers its costs from insurance carriers and from other third parties whenever possible. Any amounts collected in excess of the Utility s ultimate obligations may be subject to refund to ratepayers.

The Utility s undiscounted future costs could increase to as much as $422 million if the other potentially responsible parties are not financially able to contribute to these costs, or the extent of contamination or necessary remediation is greater than anticipated. The approximately $422 million amount does not include an estimate for the cost of remediation at known sites owned or operated in the past by the Utility s predecessor corporations for which the Utility has not been able to determine whether liability exists.

The California Attorney General, on behalf of various state environmental agencies, filed claims in the Utility s Chapter 11 proceeding 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 the Utility is 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 remediation or clean-up actions. The Utility s Plan of Reorganization provides that the Utility intends to respond to these types of claims in the ordinary course of business, and since the Utility has not argued that the Chapter 11 proceeding relieves the Utility of its obligations to respond to valid environmental remediation orders, the Utility believes the California Attorney General s claims seeking specific cash recoveries are unenforceable. Environmental claims in the ordinary course of business will not be discharged in the Utility s Chapter 11 proceeding and will pass through the Chapter 11 proceeding unimpaired.

Legal Matters

In the normal course of business, the Utility is named as a party in a number of claims and lawsuits. The most significant of these are discussed below. The Utility s Chapter 11 filing on April 6, 2001, discussed in Note 2, automatically stayed the litigation described below against the Utility, except as otherwise noted.

Chromium Litigation

There are 14 civil suits pending against the Utility in several California state courts. 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 the Utility 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 the Utility s Chapter 11 filing can proceed.

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

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. Plaintiffs counsel selected ten of these initial trial plaintiffs, defense counsel selected seven of the initial trial plaintiffs, and one plaintiff and two alternates were selected at random. The Utility has filed 13 summary judgment motions or motions in limine, which are motions to exclude potentially prejudicial information, challenging the claims of the trial test plaintiffs. Two of the 13 summary judgment motions are scheduled for hearing in February 2004. The trial of the test cases is scheduled to begin in March 2004. The Utility also has filed a motion to dismiss the complaint in one of the cases. After a hearing in November 2003, the motion to dismiss was granted. The plaintiffs in that case have until March 2004 to file an amended complaint.

The Utility has recorded a $160 million reserve in its financial statements for these matters. The Utility believes that, after taking into account the reserves recorded at December 31, 2003, the ultimate outcome of this matter will not have a material adverse impact on its financial condition or future results of operations.

Recorded Liability for Legal Matters

In accordance with SFAS No. 5, Accounting for Contingencies, the Utility 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.

The provision for legal matters is included in the Utility s other noncurrent liabilities in the Consolidated Balance Sheets, and totaled approximately $205 million at December 31, 2003 and $202 million at December 31, 2002.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

	Quarter Ended			
(in millions)	December 31	September 30	June 30	March 31
2003				
Operating revenues [1]	$2,538	$3,103	$2,730	$2,067
Operating income	340	1,195	755	49
Net income	62	589	345	(73)
Income available for common stock	58	583	339	(79)
2002				
Operating revenues	$2,398	$2,949	$2,714	$2,453
Operating income [2]	547	1,059	1,059	1,248
Net income [2]	227	527	469	596
Income available for common stock	221	520	463	590

(1) Operating revenues for the quarter ended December 31, 2003, include the recognition of a regulatory liability of approximately $125 million for surcharge revenues collected during 2003.

(2) Operating income, income from continuing operations, and net income for the quarter ended March 31, 2002 includes a $970 million non-cash reduction to the costs of electricity related to a reversal of ISO charges.

$9,400,000,000

PACIFIC GAS AND ELECTRIC COMPANY

Senior Secured Bonds

PROSPECTUS
March , 2004

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 in connection with the sale of the senior bonds being registered. All amounts, other than the registration fee, are estimates.

Registration fee	$ 760,460
Printing and engraving expenses	510,000
Legal fees and expenses	8,500,000
Accounting fees and expenses	460,000
Trustee s and authenticating agent s fees and expenses	20,000
Rating agencies fees	1,613,000
Miscellaneous	150,000
Total	$ 12,013,460

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
2.1	Order Confirming Plan of Reorganization, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted)*
2.2	Order dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization and Supplementing Confirmation Order to Incorporate such Corrections
4.1	Form of Indenture of Mortgage between Pacific Gas and Electric Company and BNY Western Trust Company, as Trustee
5.1	Opinion of Orrick, Herrington & Sutcliffe LLP regarding the legality of the securities being registered
12.1	Computation of ratios of earnings to fixed charges

Number	Description
23.1	Consent of Deloitte & Touche LLP
23.2	Consent of Orrick, Herrington & Sutcliffe LLP (included in Exhibit 5.1)
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 BNY Western Trust Company, Trustee

* We undertake to provide a copy of each omitted exhibit supplementally to the SEC upon request.

Previously filed.

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 Amendment No. 1 to Registration Statement on Form S-3 to be signed on its behalf by the undersigned, thereunto duly authorized, in the city of San Francisco, California, on March 2, 2004.

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 Amendment No. 1 to 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)	March 2, 2004
* KENT M. HARVEY Kent M. Harvey	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	March 2, 2004
* DINYAR B. MISTRY Dinyar B. Mistry	Vice President and Controller (Principal Accounting Officer)	March 2, 2004
* DAVID R. ANDREWS David R. Andrews	Director	March 2, 2004
Leslie S. Biller	Director	March 2, 2004
* DAVID A. COULTER David A. Coulter	Director	March 2, 2004
* C. LEE COX C. Lee Cox	Director	March 2, 2004
* WILLIAM S. DAVILA William S. Davila	Director	March 2, 2004
* ROBERT D. GLYNN, JR. Robert D. Glynn, Jr.	Director	March 2, 2004

* DAVID M. LAWRENCE David M. Lawrence	Director	March 2, 2004

Signature	Title	Date
* MARY S. METZ Mary S. Metz	Director	March 2, 2004
* CARL E. REICHARDT Carl E. Reichardt	Director	March 2, 2004
* BARRY LAWSON WILLIAMS Barry Lawson Williams	Director	March 2, 2004

*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, 2003 and 2002, and for each of the three years in the period ended December 31, 2003 and have issued our report thereon dated February 18, 2004 (March 1, 2004 as to the last three paragraphs of Note 1), (which report expresses an unqualified opinion and includes explanatory paragraphs relating to (i) the adoption of new accounting standards in 2003 and in 2001, 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 18, 2004

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:					
2003:					
Allowance for uncollectible accounts(1)	$ 59	$ 42	$ —	$ 33(2)	$ 68
2002:					
Allowance for uncollectible accounts(1)	$ 48	$ 34	$ (2)	$ 23(2)	$ 59
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	$ —

(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

Number	Description
2.1	Order Confirming Plan of Reorganization, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted)
2.2	Order dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization and Supplementing Confirmation Order to Incorporate such Corrections
4.1	Form of Indenture of Mortgage between Pacific Gas and Electric Company and BNY Western Trust Company, as Trustee
5.1	Opinion of Orrick, Herrington & Sutcliffe LLP regarding the legality of the securities being registered
12.1	Computation of ratios of earnings to fixed charges
23.1	Consent of Deloitte & Touche LLP
23.2	Consent of Orrick, Herrington & Sutcliffe LLP (included in Exhibit 5.1)
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 BNY Western Trust Company, Trustee

Previously filed.