EDGAR Online

PG&E CORP

FORM 10-K
(Annual Report)

Filed 03/05/02 for the Period Ending 12/31/01

Address	77 BEALE STREET P.O. BOX 770000 SAN FRANCISCO, CA 94177
Telephone	4152677000
CIK	0001004980
Symbol	PCG
SIC Code	4931 - Electric and Other Services Combined
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

Powered By EDGAR Online
http://www.edgar-online.com
© Copyright 2013, EDGAR Online, Inc. All Rights Reserved.
Distribution and use of this document restricted under EDGAR Online, Inc. Terms of Use.

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2001
OR

☐

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

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

Pacific Gas and Electric Company
77 Beale Street
P.O. Box 770000
San Francisco, California
(Address of principal executive offices)
94177
(Zip Code)
(415) 973-7000
(Registrant's telephone number, including area code)

PG&E Corporation
One Market, Spear Tower
Suite 2400
San Francisco, California
(Address of principal executive offices)
94105
(Zip Code)
(415) 267-7000
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
PG&E Corporation	
Common Stock, no par value	New York Stock Exchange and
Preferred Stock Purchase Rights	Pacific Exchange
Pacific Gas and Electric Company	
First Preferred Stock, cumulative, par value $25 per share:	American Stock Exchange and Pacific Exchange
Redeemable: 7.04%, 5% Series A, 5%, 4.80%, 4.50%, 4.36%	
Mandatorily Redeemable: 6.57%, 6.30%	
Nonredeemable: 6%, 5.50%, 5%	
7.90% Cumulative Quarterly Income Preferred Securities Series A, due 2025	American Stock Exchange and Pacific Exchange

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ **No** ☐

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

Aggregate market value of the voting common equity held by non-affiliates of the registrant as of February 1, 2002:
PG&E Corporation Common Stock $8,074 million

Common Stock outstanding as of February 1 , 2002:
PG&E Corporation: 387,922,052
Pacific Gas and Electric Company: Wholly owned by PG&E Corporation

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved.

(1) Designated portions of the combined Annual Report to Shareholders — Part I (Item 1), Part II (Items 5, 6, 7, 7A, and 8), Part

for the year ended December 31, 2001	IV (Item 14)
(2) Designated portions of the Joint Proxy Statement relating to the 2002 Annual Meeting of Shareholders	Part III (Items 10, 11, 12, and 13)

TABLE OF CONTENTS

		Page
	Glossary of Terms	iv
	PART I	
Item 1.	Business	1
	GENERAL	1
	Corporate Structure and Business	1
	Competition and the Changing Regulatory Environment	5
	The Electric Industry	6
	The Natural Gas Industry	6
	Generation, Energy Marketing and Trading, and Natural Gas Transmission	7
	Regulation of PG&E Corporation	7
	Regulation of Pacific Gas and Electric Company	10
	Federal Regulation	10
	State Regulation	10
	Licenses and Permits	11
	Regulation of PG&E National Energy Group, Inc. Businesses	11
	Federal Regulation	11
	State and Other Regulations	12
	UTILITY OPERATIONS	13
	Ratemaking Mechanisms	13
	General Rate Case	13
	Cost of Capital	13
	Electric Ratemaking	14
	Rate Stabilization Plan Proceeding	14
	1999 General Rate Case	15
	2003 General Rate Case	15
	2001 Attrition Rate Adjustment Request	16
	Retained Generation Ratemaking Proceeding	16
	Revenue Adjustment Proceeding	16
	Annual Transition Cost Proceeding	17
	Electric Industry Restructuring Implementation Costs	17
	Electric Restructuring Costs Account (ERCA)	17
	Revenues from Must-Run Contracts	18
	FERC Transmission Owner Rate Case	18
	AB 1890 Electric Base Revenue Increase	18
	Electric Transmission Rates	19
	Post-Transition Period Ratemaking Proceeding	19
	Gas Ratemaking	19
	Gas Accord	19
	General Rate Case	19
	The Core Fixed Cost Account (CFCA)	19
	Gas Procurement Costs	20
	The Biennial Cost Allocation Proceeding (BCAP)	20
	Public Purpose Programs	20
	Electric Utility Operations	21
	California Electric Industry Restructuring	21
	Generation Divestiture and Market Valuation	21

Page

The Power Exchange, Independent System Operator, and the Buy/Sell Requirement 22
The Rate Freeze and Transition Cost Recovery 24
New California Legislation 26
FERC Proceedings and Decisions 27
Electric Operating Statistics 29
Electric Resources 30
Generating Capacity 30
Hydroelectric Generation Assets 31
Diablo Canyon Nuclear Power Plant 31
Diablo Canyon Ratemaking 32
Nuclear Fuel Supply and Disposal 32
Insurance 33
Decommissioning 33
Other Electric Resources 34
QF Generation and Other Power Purchase Contracts 34
Bilateral Agreements 36
Electric Transmission and Distribution 37
Gas Utility Operations 38
Gas Operating Statistics 40
Natural Gas Supplies 41
Gas Regulatory Framework 42
Transportation Commitments 43
PG&E NATIONAL ENERGY GROUP, INC . 43
Natural Gas Transmission Business 43
Gas Transmission-Northwest (GTN) 43
Iroquois Pipeline 44
North Baja Pipeline 44
Integrated Energy and Marketing Business 45
Independent Power Projects 46
Merchant Power Plants 46
Contractual Control of Generating Capacity 46
Description of Generating Facilities in Operation and Construction 47
Greenfield Development 48
Equipment Procurement 48
Turbine Technology 49
Construction Issues 50
Energy Marketing and Trading 50
Electricity 50
Natural Gas 50
Coal, Oil and Emissions 51
Fuel Supply, Transport and Electric Transmission Management 51
Load Management or Full Requirements Arrangements 51
ENVIRONMENTAL MATTERS 52
Environmental Matters 52
Environmental Protection Measures 52
Air Quality 52
Water Quality 54
Hazardous Waste Compliance and Remediation 55
Potential Recovery of Hazardous Waste Compliance and Remediation Costs 57
Compressor Station Litigation 58

		Page
	Electric and Magnetic Fields	58
	Low Emission Vehicle Programs	59
Item 2.	Properties	60
Item 3.	Legal Proceedings	60
	Pacific Gas and Electric Company Bankruptcy	60
	Pacific Gas and Electric Company vs. California Public Utilities Commissioners	63
	Federal Securities Lawsuit	64
	In re: Natural Gas Royalties Qui Tam Litigation	64
	Baldwin Associates	65
	Wayne Roberts	65
	Moss Landing Power Plant	66
	Compressor Station Chromium Litigation	66
	California Energy Trading Litigation	68
	California Attorney General Complaint	68
	Complaint filed by the City and County of San Francisco, and the People of the State of California	69
	Sierra Pacific Industries v. Pacific Gas and Electric Company	69
	William Ahern v. Pacific Gas, and Electric Company	70
Item 4.	Submission of Matters to a Vote of Security Holders	70
	EXECUTIVE OFFICERS OF THE REGISTRANTS	71
	PART II	
Item 5.	Market for the Registrant's Common Equity and Related Stockholder Matters	74
Item 6.	Selected Financial Data	74
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	74
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	74
Item 8.	Financial Statements and Supplementary Data	74
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	75
	PART III	
Item 10.	Directors and Executive Officers of the Registrant	75
Item 11.	Executive Compensation	75
Item 12.	Security Ownership of Certain Beneficial Owners and Management	75
Item 13.	Certain Relationships and Related Transactions	75
	PART IV	
Item 14.	Exhibits, Financial Statement Schedules, and Reports on Form 8-K	76
	Signatures	83

GLOSSARY OF TERMS

AB 1890	Assembly Bill 1890, the California electric industry restructuring legislation
AEAP	Annual Earnings Assessment Proceeding
Alstom	Alstom Power, Inc.
ATCP	Annual Transition Cost Proceeding
BACT	Best available control technology
BCAP	Biennial Cost Allocation Proceeding
bcf	billion cubic feet
Betz	Betz Chemical Company
BFM	block forward market
BTA	best technology available
Btu	British thermal unit
CARE	California Alternate Rates for Energy
CCAA	California Clean Air Act
CEC	California Energy Commission
Central Coast Board	Central Coast Regional Water Quality Control Board
CEQA	California Environmental Quality Act
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFCA	Core Fixed Cost Account
CLF	Conservation Law Foundation
core customers	residential and smaller commercial gas customers
core subscription customers	noncore customers who choose bundled service
CPIM	core procurement incentive mechanism
CPUC	California Public Utilities Commission
CTC	competition transition charge
Diablo Canyon	Diablo Canyon Nuclear Power Plant
DOE	United States Department of Energy
DWR	California Department of Water Resources
EIR	environmental impact report
EMF	electric and magnetic fields
EPA	United States Environmental Protection Agency
ERCA	Electric Restructuring Costs Account
ESP	energy service provider
EWG	exempt wholesale generator
FERC	Federal Energy Regulatory Commission
GABA	Generation Asset Balancing Account
Gas Accord	Gas Accord Settlement
GRC	General Rate Case
Holding Company Act	Public Utility Holding Company Act of 1935
Humboldt Unit 3	Humboldt Bay Power Plant (Unit 3)
HWRC	hazardous waste remediation costs
ICIP	Incremental Cost Incentive Price
IPP	independent power producer
ISO	Independent System Operator
kV	kilovolts
kVa	kilovolt-amperes
kW	kilowatts
LEV	low emission vehicle
LIEE	Low-Income Energy Efficiency
Mcf	thousand cubic feet
MDt	thousand decatherms
MMcf	million cubic feet
MW	megawatts
MWh	megawatt-hour

NEES	New England Electric System
NEIL	Nuclear Electric Insurance Limited
NGL	natural gas liquids
NOI	Notice of Intent
noncore customers	industrial and larger commercial gas customers
NOx	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NTP&S	non-tariffed products and services
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
ORA	Office of Ratepayer Advocates, a division of the California Public Utilities Commission
PBR	performance-based ratemaking
PECA	Purchased Electric Commodity Account
PGA	Purchased Gas Account
PG&E Energy	PG&E NEG's integrated energy and marketing segment
PG&E ET	PG&E Energy Trading Holdings Corporation and its subsidiaries
PG&E Gen LLC	PG&E Generating Company, LLC and its affiliates
PG&E GTC	PG&E Gas Transmission Corporation and its subsidiaries
PG&E GTN	PG&E Gas Transmission, Northwest Corporation
PG&E NBP	PG&E North Baja Pipeline, LLC
PG&E NEG	PG&E National Energy Group, Inc.
PG&E Pipeline	PG&E NEG's interstate pipeline operations
PPPs	public purpose programs
Price Act	Price Anderson Act
PRP	potentially responsible party
PTO	Participating Transmission Owner
PURPA	Public Utility Regulatory Policies Act of 1978
PX	California Power Exchange
PY	Program Year
QF	qualifying facility
RAP	Revenue Adjustment Proceeding
RCRA	Resource Conservation and Recovery Act
RMR	reliability must-run
ROE	return on common equity
ROR	rate of return
RSP	Rate Stabilization Plan
RTO	regional transmission organization
SEC	Securities and Exchange Commission
SCS	Scheduling Coordinator Services
SO2	sulfur dioxide
SRAC	short-run avoided costs
TAC	Transmission Access Charge
TCBA	Transition Cost Balancing Account
throughput	the amount of natural gas transported through a pipeline system
TRA	Transition Revenue Account
TRBA	Transition Revenue Balancing Account
Transwestern	Transwestern Pipeline Company
TURN	The Utility Reform Network
USGenNE	USGen New England, Inc.

PART I

ITEM 1. Business.

GENERAL

Corporate Structure and Business

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. Effective January 1, 1997, Pacific Gas and Electric Company (sometimes referred to herein as the "Utility") and its subsidiaries became subsidiaries of PG&E Corporation, which was incorporated in 1995. Pacific Gas and Electric Company, incorporated in California in 1905, is an operating public utility engaged principally in the business of providing electricity and natural gas distribution and transmission services throughout most of Northern and Central California. The Utility is primarily regulated by the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). In the holding company reorganization, Pacific Gas and Electric Company's outstanding common stock was converted on a share-for-share basis into PG&E Corporation common stock. Pacific Gas and Electric Company's debt securities and preferred stock were unaffected and remain securities of Pacific Gas and Electric Company. PG&E Corporation's other significant subsidiary is PG&E National Energy Group, Inc. (PG&E NEG), headquartered in Bethesda, Maryland. PG&E NEG was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. Shortly thereafter, PG&E Corporation contributed various subsidiaries to PG&E NEG.

On April 6, 2001, Pacific Gas and Electric Company filed a voluntary petition for relief under the provisions of Chapter 11 of the U.S. Bankruptcy Code (Bankruptcy Code) in the U.S. Bankruptcy Court for the Northern District of California (Bankruptcy Court). Pursuant to Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. The factors causing the Utility to take this action are discussed in "Management's Discussion and Analysis" and in Notes 2 and 3 of the "Notes to the Consolidated Financial Statements," appearing in the PG&E Corporation and Pacific Gas and Electric Company combined 2001 Annual Report to Shareholders, which information is incorporated by reference into this report. On September 20, 2001, the Utility and PG&E Corporation jointly filed with the Bankruptcy Court a proposed plan of reorganization of the Utility (the Plan) and the proposed disclosure statement describing the proposed plan. Both the Plan and the disclosure statement were subsequently amended on December 19, 2001 and February 4, 2002. For more information about the proposed Plan, see Item 3—Legal Proceedings, below and Note 2 of the Notes to the Consolidated Financial Statements in the 2001 Annual Report to Shareholders.

The principal executive office of PG&E Corporation is located at One Market, Spear Tower, Suite 2400, San Francisco, California 94105, and its telephone number is (415) 267-7000. The principal executive offices of Pacific Gas and Electric Company are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and its telephone number is (415) 973-7000.

PG&E NEG is an integrated energy company with a strategic focus on power generation, natural gas transmission, and, wholesale energy marketing and trading in North America. PG&E NEG and its subsidiaries have integrated their generation, development, and energy marketing and trading activities in an effort to create energy products in response to customer needs, increase the returns from operations, and identify and capitalize on opportunities to optimize generating and pipeline capacity. PG&E NEG accounts for its business in two reportable operating segments: the integrated energy and marketing business is referred to as PG&E Energy and the interstate pipeline operations are referred to as PG&E Pipeline. PG&E Energy's principal subsidiaries include PG&E Generating Company, LLC and its subsidiaries (collectively PG&E Gen LLC), and PG&E Energy Trading Holdings Corporation, which owns PG&E Energy Trading-Power, L.P. and PG&E Energy Trading-Gas

Corporation and other affiliates (collectively, PG&E ET). PG&E Pipeline is comprised of PG&E Gas Transmission Corporation and its subsidiaries (collectively PG&E GTC). PG&E GTC includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries (collectively PG&E GTN) and PG&E North Baja Pipeline, LLC (PG&E NBP). For more information about PG&E NEG's businesses, see "PG&E National Energy Group" below.

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

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

PG&E Corporation has identified three reportable operating segments, which were determined based on similarities in economic characteristics, products and services, types of customers, methods of distribution, the regulatory environment, and how information is reported to PG&E Corporation's key decision makers. These segments represent a change in the reportable segments from those reported in the year 2000. In accordance with accounting principles generally accepted in the United States, prior year segment information has been restated to conform to the current segment presentation. The Utility is one reportable operating segment. The other two reportable operating segments are PG&E Energy and PG&E Pipeline. These three reportable operating segments provide different products and services and are subject to different forms of regulation or jurisdictions. Financial information about each reportable operating segment is provided in "Management's Discussion and Analysis" in the 2001 Annual Report to Shareholders and in Note 17 of the "Notes to Consolidated Financial Statements" beginning on page 123 of the 2001 Annual Report to Shareholders, which information is incorporated by reference into this report.

As of December 31, 2001, PG&E Corporation had approximately $35.9 billion in assets. Of this amount, Pacific Gas and Electric Company had $25.1 billion in assets. PG&E Corporation generated approximately $23 billion in operating revenues for 2001. Of this amount, the Utility generated $10.5 billion in operating revenues for 2001. As of December 31, 2001, PG&E Corporation and its subsidiaries and affiliates had 22,619 employees (including 20,155 employees of the Utility).

The following report includes forward-looking statements about the future that are necessarily subject to various risks and uncertainties. These statements are based on current expectations and assumptions which management believes are reasonable and on information currently available to management. These forward-looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," and other similar expressions. Actual results could differ materially from those contemplated by the forward-looking

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

- the outcome of the Utility's bankruptcy case, including:
  - whether the Bankruptcy Court approves the amended disclosure statement relating to the Utility's proposed plan of reorganization (Plan) to be submitted to comply with the Bankruptcy Court's February 7, 2002 decision;
  - whether the Bankruptcy Court confirms the Utility's Plan as amended to comply with the Bankruptcy Court's February 7, 2002 decision;
  - whether the Bankruptcy Court confirms the alternative plan of reorganization to be submitted by the CPUC and the terms of such a plan;
  - whether other parties submit alternative proposed plans of reorganization after the expiration of the period during which only the Utility may file a proposed plan;
  - whether the CPUC takes action that would negatively affect the feasibility of the proposed Plan;
  - whether the Plan is materially modified or amended;
  - whether the Utility is required to re-assume the obligation to purchase power for its customers from the California Department of Water Resources (DWR) under circumstances that threaten to undermine the Utility's creditworthiness, financial condition, or results of operation;
  - whether the Utility is required to accept assignment of the DWR's power purchase contracts;
  - assuming the Bankruptcy Court confirms the proposed Plan, whether such confirmation can be challenged or appealed and the impact of any delay caused by such challenges or appeals on continued creditor support of the Plan and on continued feasibility of the Plan;
  - whether, even if confirmed, the Plan becomes effective, which may be affected by, among other factors:
  - risks relating to the issuance of new debt securities by each of the disaggregated entities, including higher interest rates than are assumed in the financial projections which could affect the amount of cash that could be raised to satisfy allowed claims, and the inability to successfully market the debt securities due to, among other reasons, an adverse change in market conditions or in the condition of the disaggregated entities before completion of the offerings;
  - whether a favorable tax ruling or opinion is obtained regarding the tax-free nature of the transactions contemplated in the Plan;
  - whether approval is obtained from the various federal regulatory agencies to implement the transactions contemplated in the Plan, the timing of that approval, and the timing and success of any appeals of such regulatory orders;
- assuming the Plan becomes effective , whether the Utility will be able to successfully disaggregate its businesses;
- the effect of the Utility's bankruptcy proceedings on PG&E Corporation and PG&E NEG and in particular, the impact a protracted delay in the Utility's bankruptcy proceedings could have on PG&E Corporation's liquidity and access to capital markets;

- the outcome of the CPUC's pending investigation into whether the California investor-owned utilities, including the Utility, have complied with past CPUC decisions, rules, or orders authorizing their holding company formations, the outcomes of the lawsuits brought by the California Attorney General and the City and County of San Francisco and People of the State of California, against PG&E Corporation alleging unfair or fraudulent business acts or practices based on alleged violations of conditions established in the CPUC's holding company decisions, and the outcome of the California Attorney General's petition requesting revocation of PG&E Corporation's exemption from the Public Utility Holding Company Act of 1935, and the effect of such outcomes, if any, on PG&E Corporation, the Utility, and PG&E NEG;

- the extent to which the ability of PG&E Corporation to obtain financing or capital on reasonable terms is affected by the interpretation of the CPUC's holding company conditions, conditions in the general economy, the energy markets, or capital markets;
- the outcome of the Utility's various regulatory proceedings pending at the CPUC, including the proceeding to determine future ratemaking for the Utility's retained generation (primarily hydroelectric assets and the Diablo Canyon Nuclear Power Plant), the 2002 attrition rate adjustment request, and the 2003 General Rate Case;
- whether the CPUC's March 27, 2001 accounting decision regarding the Utility's under-collected wholesale power purchase costs is upheld and whether the Utility's lawsuit against the CPUC for recovery of those costs is successful;

- any changes in the amount of transition costs the Utility is allowed to collect from its customers, and the timing of the completion of the Utility's transition cost recovery;

- the amount and timing of regulatory valuation of the Utility's hydroelectric and other non-nuclear generation assets;

- the impact on earnings of the future operating performance at the Utility's Diablo Canyon Nuclear Power Plant (Diablo Canyon);

- legislative or regulatory changes affecting the electric and natural gas industries in the United States, including the pace and extent of efforts to restructure the electric and natural gas industries;

- the volatility of commodity fuel and electricity prices (which may result from a variety of factors, including weather; the supply and demand for energy commodities; the availability of competitively priced alternative energy sources; the level of production and availability of natural gas, crude oil, and coal; transmission or transportation constraints; federal and state energy and environmental regulation and legislation; the degree of market liquidity; and natural disasters, wars, embargoes, and other catastrophic events); any resulting increases in the cost of producing power and decreases in prices of power sold, and whether the Utility's and PG&E NEG's strategies to manage and respond to such volatility are successful;

- PG&E NEG's ability to obtain financing from third parties or from PG&E Corporation for its planned development projects and related equipment purchases and to refinance PG&E NEG's and its subsidiaries' existing indebtedness as it matures, in each case, on reasonable terms, while preserving PG&E NEG's credit quality; which ability could be negatively affected by conditions in the general economy, the energy markets, or capital markets; and the extent to which the CPUC's holding company conditions may be interpreted to restrict PG&E Corporation's ability to provide financial support to PG&E NEG;

- the extent to which PG&E NEG's current or planned development of generation, pipeline, and storage facilities are completed and the pace and cost of that completion, including the extent to which commercial operations of these development projects are delayed or prevented because of various development and construction risks such as PG&E NEG's failure to obtain necessary permits or equipment, the failure of third-party contractors to perform their contractual obligations, or the failure of necessary equipment to perform as anticipated;
- the extent and timing of generating, pipeline, and storage capacity expansion and retirements by others;
- the performance of PG&E NEG's projects and the success of PG&E NEG's efforts to invest in and develop new opportunities;
- restrictions imposed upon PG&E Corporation and PG&E NEG under certain term loans of PG&E Corporation including maintenance of minimum segregated cash balances by PG&E Corporation and prohibitions on payment of dividends by both PG&E Corporation and PG&E NEG;
- future sales levels, which, in the case of the Utility, will be affected by when the CPUC ultimately determines that direct access has been suspended and the level of exit fees that may be imposed on direct access customers; general economic and financial market conditions; and changes in interest rates;
- volatility resulting from mark-to-market accounting and the extent to which the assumptions underlying PG&E NEG's and the Utility's mark-to market accounting and risk management programs are not realized;
- the effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant;
- heightened rating agency criteria and the impact of changes in credit ratings on PG&E NEG's future financial condition, particularly a downgrade below investment grade which would impair PG&E NEG's ability to meet liquidity calls in connection with its trading activities and obtain financing for its planned development projects;
- new accounting pronouncements; and
- the outcome of pending litigation.

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

Competition and the Changing Regulatory Environment

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

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 those customers and competitors by providing for more competition in the energy industry. Regulators and legislators required utilities to "unbundle" rates (separate their various energy services and the prices of those services) and to sell their electric generation facilities to outside parties. This was intended to allow customers to compare unit prices of the utilities and other providers when selecting their energy service provider.

The Electric Industry . In 1998, California became one of the first states in the country to implement electric industry restructuring with the goal of establishing a competitive market for electric generation. The framework for electric industry restructuring was established in Assembly Bill 1890 (AB 1890), passed by the California Legislature and signed by the Governor in 1996, which turned over operation of the state's transmission system to the California Independent System Operator (ISO) and the pricing of unregulated generation to the California Power Exchange (PX). Beginning March 31, 1998, Californians were given the choice to purchase electricity from generation providers other than the traditional utilities (such as unregulated power generators and unregulated retail electricity suppliers such as marketers, brokers, and aggregators). Purchasing electric power from an alternative generation provider is called "direct access." For those customers who did not choose direct access, investor-owned utilities were to continue to purchase electric power on their behalf. Investor-owned utilities continue to provide distribution services to substantially all customers within their service territories, including those customers who choose direct access.

As required by AB 1890, electric rates for all customers were frozen at the level in effect on June 10, 1996, and, beginning January 1, 1998, rates for residential and small commercial customers were reduced by 10% from 1996 levels. (In January and March 2001, the CPUC increased rates in order for the utilities to pay their ongoing wholesale power costs.) Retail rates were frozen in order to provide an opportunity for the utilities to recover the costs of their generation assets that were presumed to be above the costs representative of a fully competitive market (i.e., transition costs). Most transition costs must be recovered during a transition period that ends the earlier of December 31, 2001, or when the California investor-owned utility has recovered its eligible transition costs.

Beginning in June 2000, market prices for wholesale electricity in California began to escalate. Prices moderated somewhat in September and October of 2000, only to skyrocket unexpectedly to much higher levels in mid-November and December of 2000. The Utility's revenues from frozen retail rates were insufficient to recover the Utility's cost of purchasing wholesale power for its customers at FERC-approved market-based rates. This created a financial crisis for the Utility and its parent, PG&E Corporation. The Utility continued to finance the higher costs of wholesale electric power while it worked with interested parties to evaluate various solutions to the energy crisis. In January 2001, the principal credit rating agencies reduced the Utility's credit ratings to below investment grade, precluding further financing for power purchases and resulting in an event of default under the Utility's $850 million revolving credit facility, which left the Utility without available credit lines to pay maturing commercial paper.

For more information about California electric industry restructuring, see "Utility Operations—Electric Utility Operations—California Electric Industry Restructuring" below.

As of December 31, 2001, 17 other states had enacted electric industry restructuring legislation or issued comprehensive regulatory orders, including Connecticut, Illinois, Massachusetts, New Jersey, New York, Rhode Island, and Texas. Seven states, including Montana, Nevada, New Mexico, and Oregon have delayed their efforts to deregulate the electric industry in their own state.

The Natural Gas Industry. Restructuring of the natural gas industry on both the national and the state level has given choices to California utility customers to meet their gas supply needs. FERC Order 636 issued in 1992 required interstate pipeline companies to divide their services into separate gas commodity sales, transportation, and storage services. Under Order 636, interstate gas pipelines must provide transportation service regardless of whether the customer (often a local gas distribution company) buys the gas commodity from the pipeline.

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

For more information about the Gas Accord and regulatory changes affecting the California natural gas industry, see "Utility Operations—Gas Utility Operations—Gas Regulatory Framework" below.

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

PG&E Energy also competes with other energy marketers and traders based on the ability to aggregate supplies at competitive prices from different sources and locations and to efficiently utilize transportation from third-party pipelines and transmission from electric utilities. These operations also compete against other energy marketers on the basis of their relative financial position and access to credit sources. This competitive factor reflects the tendency of energy customers, wholesale energy suppliers and transporters to seek financial guarantees and other assurances that their energy contracts will be satisfied. As pricing information becomes increasingly available in the energy marketing and trading business and as deregulation in the electricity markets continues to evolve, PG&E NEG may experience greater competition and downward pressure or increased volatility on per-unit profit margins.

PG&E Pipeline competes with other pipeline companies, marketers and brokers, as well as producers who are able to sell natural gas directly into the wholesale end-user markets, for transportation customers on the basis of transportation rates, access to competitively priced gas supply and growing markets and the quality and reliability of transportation services. The competitiveness of a pipeline's transportation services to any market is generally determined by the total delivered natural gas price from a particular natural gas supply basin to the market served by the pipeline.

The GTN pipeline accesses suppliers of natural gas from Western Canada and serves markets in California and Nevada, and parts of the Pacific Northwest. GTN competes with other pipelines with access to natural gas supplies in Western Canada, the Rocky Mountains, the Southwest and British Columbia.

PG&E NEG's pipeline transportation volumes are also affected by the availability and economic attractiveness of other energy sources. Hydroelectric generation, for example, may increase with ample snowfall and displace demand for natural gas as a fuel for electric generation. Finally, in providing interruptible and short-term firm transportation service, PG&E NEG competes with released capacity offered by shippers holding firm contracts for its capacity. The ability of PG&E NEG's gas transmission business to compete effectively is influenced by numerous factors, including regulatory conditions and the supply of and demand for pipeline and storage capacity.

Regulation of PG&E Corporation

PG&E Corporation and its subsidiaries are exempt from all provisions, except Section 9(a)(2), of the Public Utility Holding Company Act of 1935 (Holding Company Act) although, as discussed below, the California

Attorney General (AG) recently filed a petition with the Securities and Exchange Commission (SEC) to revoke this exemption. At present, PG&E Corporation has no expectation of becoming a registered holding company under the Holding Company Act.

PG&E Corporation is not a public utility under the laws of California and is not subject to regulation as such by the CPUC. However, the CPUC approval authorizing Pacific Gas and Electric Company to form a holding company was granted subject to various conditions related to finance, human resources, records and bookkeeping, and the transfer of customer information. The CPUC, as discussed below, recently has issued a decision asserting that it maintains jurisdiction to enforce the conditions against the holding companies and to modify, clarify or add to the conditions. The financial conditions provide that the Utility is precluded from guaranteeing any obligations of PG&E Corporation without prior written consent from the CPUC, the Utility's dividend policy shall continue to be established by the Utility's Board of Directors as though Pacific Gas and Electric Company were a stand-alone utility company, and the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, shall be given first priority by the Board of Directors of PG&E Corporation (the "first priority condition"). The conditions also provide that the Utility shall maintain on average its CPUC-authorized utility capital structure, although it shall have an opportunity to request a waiver of this condition if an adverse financial event reduces the Utility's equity ratio by 1% or more.

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

In connection with the Utility's November 2000 request for an emergency rate increase, the CPUC ordered that an audit be performed. On January 31, 2001, the CPUC released the report of its consultant of the overall financial position of the Utility, PG&E Corporation, its other affiliates, and the flow of funds between these entities and the Utility. The report covers credit and default relationships, power purchases and cash flows, cash conservation activities, accounting mechanisms to track stranded cost recovery, intercompany cash flows, affiliate earnings in the California energy market, and other matters.

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

On July 7, 2001, the AG filed a petition with the SEC requesting the SEC to review and revoke PG&E Corporation's exemption from the Holding Company Act and to begin fully regulating the activities of PG&E Corporation and its affiliates. The AG's petition requested the SEC to hold a hearing on the matter as soon as possible, and requested a response from the SEC no later than September 5, 2001. On August 7, 2001, PG&E Corporation responded in detail to the AG's petition demonstrating that PG&E Corporation met the SEC's criteria for the intrastate exemption. PG&E Corporation further contended that registration would not have avoided the dysfunctional energy market in California or the distress of California's largest utilities, which resulted from a variety of other factors, including rules preventing the Utility from passing power costs through to its customers. To date, the SEC has neither instituted an investigation nor ordered hearings regarding the matters raised in the AG's petition.

On January 9, 2002, the CPUC voted in favor of two decisions in its pending investigation. In one decision, the CPUC interpreted 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 CPUC also interpreted the first priority condition as prohibiting a holding company from (1) acquiring assets of its utility subsidiary for inadequate consideration; and (2) acquiring assets of its utility subsidiary at any price, if such acquisition would impair the utility's ability to fulfill its obligation to serve or to operate in a prudent and efficient manner.

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

On January 10, 2002, the AG filed a complaint in the San Francisco Superior Court against PG&E Corporation and its directors, as well as against the directors of the Utility, based on allegations of unfair or fraudulent business acts or practices in violation of California Business and Professions Code section 17200. Among other allegations, the AG alleges that PG&E Corporation violated the various conditions established by the CPUC in decisions approving the holding company formation. In a press release issued on January 10, 2002, the CPUC expressed support for the AG's complaint, noting that the CPUC's January 9, 2002 decision provided a basis for the AG's allegations and that the CPUC intends to join in a lawsuit against PG&E Corporation based on these issues. For more information, see "Item 3—Legal Proceedings" below.

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 AG's complaint including allegations of unfair competition in violation of California Business and Professions Code Section 17200. In addition, the complaint alleges causes of action for conversion, claiming that PG&E Corporation "took at least $5.2 billion from PG&E," and for unjust enrichment. Among other allegations, plaintiffs allege that past transfers of money from the Utility to PG&E Corporation, and allegedly used by PG&E Corporation to subsidize other affiliates of PG&E Corporation, violated various holding company conditions. Plaintiffs seek injunctive relief, the appointment of a receiver, restitution, disgorgement, the imposition of a constructive trust, civil penalties, and costs of suit. For more information, see "Item 3—Legal Proceedings" below.

PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules, and orders. Neither the Utility nor PG&E Corporation can predict what the outcomes of the

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

Regulation of Pacific Gas and Electric Company

Federal Regulation

The FERC regulates electric transmission rates and access, interconnections, operation of the California ISO and the PX, and the terms and rates of wholesale electric power sales. The ISO has responsibility for meeting applicable reliability criteria, planning transmission additions and assuring the maintenance of adequate reserves and is subject to FERC regulation of tariffs and conditions of service. The PX provided an auction process, intended to be competitive, to establish hourly transparent market clearing prices for electricity in the markets operated by the PX. In addition, the FERC has jurisdiction over the Utility's electric transmission revenue requirements and rates. The FERC also regulates the interstate transportation of natural gas. Further, most of the Utility's hydroelectric facilities are subject to licenses issued by the FERC.

On December 20, 1999, the FERC issued its final rule (Order No. 2000) on Regional Transmission Organizations (RTOs). The order encourages utilities owning transmission systems to form RTOs on a voluntary basis. Typically, the establishment of these entities results in the consolidation of transmission charges imposed by successive transmission systems into a single tariff. The Utility is a participant in the ISO; however, the FERC has not yet approved the ISO's status as a RTO under Order No. 2000.

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

State Regulation

The CPUC has jurisdiction to set retail rates and conditions of service for Pacific Gas and Electric Company's electric distribution, gas distribution, and gas transmission services in California. The CPUC also has jurisdiction over the Utility's sales of securities, dispositions of utility property, energy procurement on behalf of its electric and gas retail customers, and certain aspects of the Utility's siting and operation of its electric and gas transmission and distribution systems. In an order issued on December 15, 2000, addressing the dysfunctional California electric market, the FERC ordered the elimination of the CPUC-imposed requirement that all generation owned or controlled by the Utility be sold for resale into the PX. Thus, ratemaking for retail sales from the Utility's remaining generation facilities is under the jurisdiction of the CPUC. To the extent such power is sold for resale into wholesale markets, however, it is under the ratemaking jurisdiction of the FERC. The CPUC also conducts various reviews of utility performance and conducts investigations into various matters, such as deregulation, competition, and the environment, in order to determine its future policies. The CPUC consists of five members appointed by the Governor and confirmed by the State Senate for six-year terms.

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

Licenses and Permits

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

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

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

Federal Regulation

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

PG&E NEG-affiliated projects are also subject to other differing federal regulatory regimes. Those qualifying as qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA), are exempt from the Holding Company Act, certain rate filings, and accounting, record keeping, and reporting requirements that the FERC otherwise imposes and from certain state laws. Others qualify as Exempt Wholesale Generators (EWGs) under the National Energy Policy Act of 1992. EWGs are not regulated under the Holding Company Act, but are subject to FERC and state regulation, including rate approval.

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

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

The FERC issued a new license for PG&E NEG's projects located on the Deerfield River on April 7, 1997 and a new license application for the Fifteen Mile Falls project (located on the Connecticut River) was filed July 30, 1999 and is still pending. This relicensing proceeding is being undertaken through the FERC's alternative collaborative process rather than through its more traditional, formal administrative process. No competing license applications have been filed for these projects and there is no indication that the FERC will

decommission any of these projects. Although PG&E NEG expects that the FERC will issue the new license for the Fifteen Mile Falls project, it did not do so by the July 31, 2001 expiration date. However, it did issue an annual extension of the license and PG&E NEG anticipates that it will issue additional annual extensions until such time that a new license is issued.

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

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

State and Other Regulations

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

In addition, the National Energy Board of Canada and the Canadian gas-exporting provinces issue licenses and permits for removal of natural gas from Canada. The Mexican Comisión Reguladoro de Energía, or CRE, issues various licenses and permits for the importation of gas into Mexico. These requirements are similar to the requirements of the U.S. Department of Energy for the importation and exportation of gas.

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

UTILITY OPERATIONS

Pacific Gas and Electric Company provides regulated electric and gas distribution and transmission services in Northern and Central California. The Utility's service territory covers 70,000 square miles with an estimated population of approximately 13 million and includes all or portions of 48 of California's 58 counties. The area's diverse economy includes aerospace, electronics, computer technology, financial services, food processing, petroleum refining, agriculture, and tourism.

Ratemaking Mechanisms

Customer rates are determined by the FERC or the CPUC and are designed to recover the Utility's anticipated reasonable costs and a fair rate of return. Some rates incorporate a performance incentive mechanism by providing rewards and penalties for meeting certain performance criteria. Some of the ratemaking mechanisms affecting both electricity and gas distribution operations are discussed below.

General Rate Case . The CPUC authorizes an amount, known as "base revenues," to be collected from ratepayers to recover the Utility's basic business and operational costs for its gas and electric distribution operations. Base revenues include non-fuel-related operating and maintenance costs, depreciation, taxes, and a return on invested capital. These revenue requirements are authorized by the CPUC in General Rate Case (GRC) proceedings every three years based on a forecast of costs for a test year. (The return component of the Utility's revenue requirement is computed using the overall cost of capital authorized in other proceedings.) The test year is the first year of the three-year GRC period and the GRC application is usually filed more than a year before the test year begins, based on test year estimates. Approximately three months before the GRC application is filed, the Utility must file with the CPUC a Notice of Intent (NOI) to file the GRC application. In the NOI, the Utility must provide detailed exhibits and workpapers to the CPUC to support its test year estimates to be included in the application. For the remaining two years, the Utility may apply for a yearly increase in base revenues (known as an attrition rate adjustment) to reflect inflation and the growth in capital investments necessary to serve customers. Following the revenue requirement phase of a GRC, the CPUC conducts a rate design phase, which allocates revenue requirements and establishes rate levels for the different classes of customers. Recent GRCs are discussed below.

Cost of Capital. Each year, the Utility files an application with the CPUC to determine the authorized rate of return that the Utility may earn on its electric and gas distribution assets and recover from ratepayers. Since February 17, 2000, the Utility's adopted return on common equity (ROE) has been 11.22% on electric and gas distribution operations, resulting in an authorized 9.12% overall rate of return (ROR). The Utility's earlier adopted ROE was 10.6%. The adopted ROE for 2000 resulted in an increase of approximately $49 million in electric and gas distribution revenues. In May 2000, the Utility filed an application with the CPUC to establish its authorized ROR for electric and gas distribution operations for 2001. The application requested a ROE of 12.4% and an overall ROR of 9.75%. If granted, the requested ROR would increase electric distribution revenues by approximately $72 million and gas distribution revenues by approximately $23 million. The application also requests authority to implement an Annual Cost of Capital Adjustment Mechanism for 2002 through 2006 that would replace the annual cost of capital proceedings. The proposed adjustment mechanism would modify the Utility's cost of capital based on changes in an interest rate index. The Utility also proposes to maintain its currently authorized capital structure of 46.2% long-term debt, 5.8% preferred stock, and 48% common equity. In March 2001, the CPUC issued a proposed decision recommending no change to the current 11.22% ROE for 2001. A final decision has not been issued.

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

Electric Ratemaking

As required by AB 1890, electric rates for all customers were frozen at the level in effect on June 10, 1996, and, beginning January 1, 1998, rates for residential and small commercial customers were reduced by 10% from 1996 levels. In January and March 2001, the CPUC increased retail rates in order for the utilities to pay a portion of their future wholesale power costs. Under AB 1890, the rate freeze is supposed to end the earlier of March 31, 2002, or when the Utility has recovered its eligible transition costs (uneconomic generation-related costs). Most transition costs must be recovered during a transition period that ends the earlier of December 31, 2001, or when the Utility has recovered its eligible transition costs.

The Utility repeatedly has advised the CPUC that it had recovered all of its transition costs and has asked the CPUC to recognize that the rate freeze already has ended for the Utility's customers. After the rate freeze, changes in the Utility's electric revenue requirements in general will be reflected in rates. However, the CPUC has not yet determined that the rate freeze has ended for the Utility's customers.

Rate Stabilization Plan Proceeding . Consistent with the Utility's position that it had recovered its transition costs thus requiring an end to the rate freeze, in November 2000, the Utility filed its application with the CPUC seeking approval of a five-year rate stabilization plan (RSP) designed to protect the Utility's customers from the high and volatile wholesale power prices, while increasing rates effective January 1, 2001, to allow the Utility to begin recovery of its past and ongoing wholesale power purchase costs. The Utility again asserted that the rate freeze had ended at least as early as August 2000 and that it should be permitted to recover its wholesale power costs through retail rates in accordance with prior CPUC decisions. The Utility requested an immediate and interim rate increase of approximately $0.03 per kilowatt-hour (kWh), plus the adoption of a mechanism by which additional rate increases would be provided, as necessary, if unrecovered costs built up to a predetermined level. The Utility also filed the tariff changes needed to end the freeze as required by the CPUC's previous decisions finding that the rate freeze should end as soon as the costs associated with the Utility's generation assets and obligations were recovered. The CPUC has not acted on the Utility's end-of-rate freeze tariff filing.

After a month of procedural delays, the CPUC held emergency hearings in late December 2000 and early January 2001. During the hearings, the CPUC ordered further audits of the utilities' financial conditions, and refused to consider the utilities' evidence that they had met the conditions for ending the rate freeze and thus should be permitted to recover past uncollected wholesale power costs. On January 4, 2001, the CPUC granted a rate increase of $0.01 per kWh on a temporary 90-day basis and subject to refund. The CPUC decision found that the utilities' financial conditions justified the increase but refused to lift the rate freeze or grant a rate increase sufficient to avoid continuing undercollection of wholesale power costs, which all parties acknowledged were then significantly higher than the amounts available collected from customers under the current rate freeze.

Furthermore, the CPUC stated that the rate increase could only be applied to ongoing power costs. The CPUC also rejected the Utility's request for adoption of a mechanism which would provide for subsequent rate increases triggered by growing undercollections. The rate adjustment was projected to raise only approximately $70 million in cash per month for three months, an amount that was clearly inadequate in light of the approximately $210 million that the Utility was paying per week in net power procurement. Thus, the rate increase was grossly insufficient to raise enough cash for the Utility to pay its ongoing procurement costs, pay its past power bills, or to make further borrowing possible. Immediately following the CPUC decision, the Utility's credit ratings were downgraded by Standard & Poor's (S&P) and Moody's Investor Services, Inc. (Moody's) and, thereafter, the Utility was precluded from purchasing power on the wholesale market.

On March 27, 2001, the CPUC authorized the Utility to add an average $0.03 per kWh surcharge to current rates and ordered that the emergency $0.01 per kWh surcharge adopted by the CPUC on January 4, 2001, be made permanent. However, although finding that the Utility was experiencing loss of credit capability and impending default, the CPUC stated that the decision was intended "to assure the continued viability of California's electric power supply, to safeguard the viability of the State's General Fund, and to minimize

credit-related supply disruptions." Thus, the CPUC mandated that the revenue generated by the $0.03 rate increase was to be used only for electric power procurement costs incurred after March 27, 2001, not for any prior unpaid power bills or debts of the Utility. The CPUC also refused to consider whether the rate freeze had already ended and refused to end it prospectively, despite the reports of its auditors confirming the accounting on which the Utility's calculation of the end of the rate freeze was based and proposals from its staff and key customer advocates that the rate freeze should be ended. Rather, as discussed below under California Electric Industry Restructuring, the CPUC made a retroactive accounting change that attempted to erase from the Utility's regulatory books the financial evidence that the Utility had fully met the conditions for an end to the rate freeze.

1999 General Rate Case . In February 2000, the CPUC issued a decision in the Utility's 1999 GRC for the period 1999 through 2001. The decision was retroactive to January 1, 1999. The CPUC authorized base revenues for the Utility's electric distribution function of approximately $2.3 billion, reflecting an increase of $377 million over base revenues authorized in 1996. On October 16, 2001, the CPUC granted applications for rehearing that had been filed by The Utility Reform Network (TURN) and another party. The applications for rehearing, which had been pending since March 2000, alleged that the CPUC committed legal error by approving funding in certain areas that were not adequately supported by record evidence. In the decision granting rehearing, the CPUC found that, in proposing a general rate increase, the Utility has the obligation to produce clear and convincing evidence for each component of its proposed revenue requirements, and the CPUC cannot grant the requested increase to the extent the Utility fails to meet that obligation. The CPUC reversed in part its prior determination regarding the adequacy of the evidence supporting the original 1999 GRC decision and reduced the adopted electric and gas distribution annual revenue requirement by approximately $40 million. In addition, the rehearing decision orders the record to be reopened to receive evidence of the actual level of 1998 electric distribution capital spending in relation to the forecast used to determine 1999 rates, possibly resulting in an adjustment of the adopted 1998 forecast level to conform to the 1998 recorded level. Following the 1998 capital spending rehearing and resolution of all other outstanding matters, a final Results of Operations analysis will be performed, and a final revenue requirement will be determined. The rehearing decision apparently intends that the revised revenue requirement would be made retroactive to January 1, 1999. On November 15, 2001, the Utility filed in the California Court of Appeal a petition for writ of review of the 1999 GRC rehearing decision and filed an application for rehearing with the CPUC. On January 9, 2002, the CPUC denied the Utility's application for rehearing of the rehearing decision.

Another CPUC decision issued on September 20, 2001, offset some of the negative impact of the 1999 GRC rehearing decision. In the September 2001 decision, the CPUC acknowledged that the models used to calculate certain tax items in the Utility's revenue requirements resulted in an incorrect calculation and granted an annual revenue requirement increase of approximately $21 million, representing an increase of $22.9 million in gas distribution revenue requirements and a $2.2 million decrease in electric revenue requirements. The revised revenue requirement resulting from both CPUC actions is retroactive to January 1, 1999. Further, in February 2002, the CPUC's consultants began an engineering audit of the Utility's 1999 distribution capital expenditures, as ordered in the CPUC's original February 17, 2000 decision regarding the 1999 GRC.

2003 General Rate Case . The 1999 GRC decision also ordered that the Utility file a 2002 GRC to determine revenue requirements for the period 2002 through 2004. In January 2001, the Utility filed a petition with the CPUC requesting that the CPUC's May 1, 2001, deadline for filing the NOI be suspended in light of the then current electricity and natural gas supply crises. On October 25, 2001, the CPUC ordered the Utility to submit an NOI to file a GRC application based on a 2003 test year (instead of a 2002 test year) by November 14, 2001. A 2003 GRC will determine revenue requirements for the period 2003 through 2005. Therefore, in the October 25, 2001, order, the CPUC requested the parties to file comments on whether the Utility needs a 2002 attrition rate adjustment (ARA) to rates authorized in the Utility's 1999 GRC. On November 9, 2001, the Utility filed comments stating its need for a 2002 ARA increase. (On January 17, 2002, the Utility filed a request with the CPUC for an interim decision to establish a mechanism to preserve the Utility's ability to recover any 2002 ARA increase the CPUC might ultimately grant.)

On November 14, 2001, the Utility informed the CPUC that is was impossible to file a fully compliant NOI based on a 2003 test year, considering that it normally takes at least six months to prepare the cost estimates and analyses necessary to develop test year estimates. On November 29, 2001, the CPUC issued an order to show

cause why the Utility should not be penalized for failing to submit the required NOI, stating that penalties could be imposed of up to $20,000 per each day the Utility fails to comply with the October 25, 2001 order. On December 20, 2001, the Utility submitted a proposal to the CPUC to resolve the issues raised in the order to show cause. Under the proposal, the Utility would file an NOI for a 2003 GRC no later than April 15, 2002 and would pay a voluntary penalty of $500 per day from January 9, 2002, to the date the NOI is filed. The Utility's proposal was supported by the CPUC staff.

2001 Attrition Rate Adjustment Request . On February 21, 2002, the CPCU approved the Utility's 2001 attrition rate adjustment request to increase electric distribution revenues by approximately $151 million, effective January 1, 2001. The 2001 capital-related portion of the increase will be subject to a true-up based on the Utility's actual 2001 capital cost. As the Utility's electric rates have been frozen in 2001, the increase in distribution-related revenues will be offset by a reduction in electric generation-related revenues in the same amount.

Retained Generation Ratemaking Proceeding. In June 2001, the Utility filed its proposed ratemaking for retained utility generation facilities and procurement costs still incurred by the Utility (Utility retained generation or "URG"). The Utility's proposal requested that the ratemaking for its retained generating facilities be set in accordance with previous and still effective CPUC decisions under AB 1890. Under the CPUC's decisions implementing AB 1890, the ratemaking for the Utility's non-nuclear generating facilities is based on their market valuation through appraisal or divestiture, and the ratemaking for the Utility's Diablo Canyon Power Plant is based on a specific "benefit sharing" formula established in a 1997 CPUC decision. Under California Public Utilities Code Section 377, as amended in January 2001 by Assembly Bill 6X for the California Legislature's 2001-02 First Extraordinary Session (AB 6X), utilities are prohibited from divesting their retained generating plants before January 1, 2006. However, Section 377, as amended, does not modify or repeal California Public Utilities Code Section 367, which still requires the CPUC to market value the generating assets of each utility by no later than December 31, 2001, based on appraisal, sale, or other divestiture.

On October 25, 2001, the CPUC issued a decision denying the Utility's request that the market value of its retained utility generating facilities be used to establish prospective ratemaking for those facilities. The CPUC said its decision did not address how to treat past uneconomic costs incurred by the Utility and that when issues concerning the termination of the rate freeze are resolved, the CPUC should address any impacts on ratemaking for the Utility's retained generation. Hearings to present evidence and testimony on the Utility's costs for its retained generation were concluded in July 2001.

On January 18, 2002, the CPUC issued a proposed decision to establish a 2002 interim revenue requirement for the Utility's retained generation. The proposed decision proposes a cost-based 2002 generation revenue requirement for URG of $2.875 billion subject to true-up to reflect actual recorded costs. In addition, the proposed decision rejects the "benefits sharing" ratemaking for Diablo Canyon in favor of cost-based rates. The proposed decision proposes that all costs, except hydroelectric and fossil power plant operating and maintenance costs, be subject to reasonableness review. The proposed decision noted that any adopted decision would not set generation rates since the CPUC must also consider the DWR's revenue requirement to be recovered from rates collected by the utilities as agents of the DWR.

On February 7, 2002, a CPUC Commissioner issued an alternate proposed decision which proposes not to reject benefit sharing for Diablo Canyon, but which would defer consideration of that issue to the pending CPUC proceeding in which the benefit sharing proposal is being addressed. The alternate also notes that the Utility's incremental cost incentive price (ICIP) performance based ratemaking mechanism is tied to recovery of transition costs. The alternate also proposes a cost-based 2002 retained generation revenue requirement for the Utility of $2.875 billion, although it is not clear the extent to which costs would be subject to future adjustments.

Revenue Adjustment Proceeding . The CPUC established a separate annual proceeding, the Revenue Adjustment Proceeding (RAP), to review and verify the amounts recorded in the Utility's Transition Revenue

Account (TRA), and to verify each electric utility's authorized revenue requirements, including any necessary adjustments to reflect the revenue requirements which are approved in other proceedings. The RAP also establishes revenue allocation and rate design, and identifies all electric balancing and memorandum accounts for continued retention or elimination. The TRA is a regulatory balancing account that is credited with total revenue collected from ratepayers through frozen rates. From this total revenue, the following items are subtracted: (1) revenues collected for transmission services and for the payment of rate reduction bond debt service, (2) the authorized revenue requirement for distribution services, public purpose programs, and nuclear decommissioning costs, and (3) electric industry restructuring implementation costs, energy procurement costs, and other costs. Remaining revenues, if any, are transferred to the Transition Cost Balancing Account (TCBA), a regulatory balancing account that tracks recovery of transition costs, to offset transition costs. In June 2001, the Utility filed its RAP application addressing revenues and costs recorded in the TRA from July 1, 1999, through April 30, 2001. The Utility has not yet revised its TRA and TCBA balances to implement a March 27, 2001, CPUC decision requiring retroactive changes to these accounting mechanisms because appeals of that decision are still pending. (See "Electric Utility Operations—California Electric Industry Restructuring" below.) On January 9, 2002, the ORA filed its report on the Utility's RAP application addressing revenues and costs recorded in the TRA from July 1, 1999, through April 30, 2001, reporting that the Utility's TRA entries during that time period comply with all applicable CPUC decisions and requirements.

Annual Transition Cost Proceeding. The Annual Transition Cost Proceeding (ATCP), applicable to all California investor-owned electric utilities, was established to verify the accounting and recording of costs and revenues in the TCBA and ensure that only eligible transition costs have been entered. The TCBA tracks the revenues available to offset transition costs, including the accelerated recovery of plant balances, and other generation-related assets and obligations. In February 2000, the Utility's request for approval of the Hunters Point power plant decommissioning cost was bifurcated into a separate phase and will be addressed in a separate decision. In September 2000, the Utility filed its 2000 ATCP application seeking approval of amounts recorded in the TCBA and generation-related memorandum accounts for the period July 1, 1999, through June 30, 2000. The CPUC has not yet issued a proposed or final decision addressing those entries. On September 4, 2001, the Utility filed its 2001 ATCP application seeking approval of amounts recorded in the TCBA and generation memorandum accounts for the period July 1, 2000, through June 30, 2001. TURN filed a protest to the Utility's application requesting that the CPUC review in the 2001 ATCP the reasonableness of the Utility's procurement and generation practices and fuel use at Humboldt Bay Power Plant during the time period July 1, 2000, through June 30, 2001. The CPUC granted TURN's request. On January 11, 2002, the Utility filed testimony supporting the reasonableness of its procurement and generation practices and fuel use at Humboldt Bay Power Plant. The Utility maintains that the CPUC has deemed its procurement practices, including block forward purchases from the PX and bilateral transactions, per se reasonable and not subject to retrospective reasonableness review. On January 22, 2002, the Utility filed a motion requesting that the CPUC issue a preliminary ruling removing the issue from the scope of the 2001 ATCP. During the time period July 1, 2000, through June 30, 2001, the Utility incurred $11.5 billion in procurement costs.

Electric Industry Restructuring Implementation Costs . Under AB 1890, certain electric industry restructuring implementation costs found reasonable by the CPUC may be recovered from electric customers. In May 1999, the CPUC approved a multi-party settlement agreement that, among other things, permits the Utility to recover 1997 and 1998 restructuring implementation costs of $41.3 million (reflecting a reduction of $10 million from the Utility's requested revenue requirement). In addition, the Utility is authorized to recover in its TRA costs related to the Consumer Education Program and the Electric Education Trust funded by the Utility and FERC-approved ISO and PX development and start-up costs. At the end of the transition period, if recovery of these restructuring implementation costs recorded in the TRA displaces recovery of transition costs recorded in the TCBA, the Utility may recover up to $95 million of such displaced transition costs after the transition period.

Electric Restructuring Costs Account (ERCA). The CPUC authorized the Utility to establish the Electric Restructuring Costs Account (ERCA) to record the restructuring implementation costs that were removed from

its 1999 GRC revenue requirement request, any unanticipated restructuring costs incurred as a result of directives from the CPUC or the FERC, and certain other costs. In July 2000, the Utility filed an application seeking approval of $142.5 million of costs recorded in the ERCA. In August 2000, protests were filed by Enron Corporation, the ORA, and TURN, challenging the evidentiary support for the costs, among other concerns. This matter is still pending.

Revenues from Must-Run Contracts . The ISO has designated certain units at electric generation facilities as necessary to be available and to run when directed to maintain the reliability of the electric transmission system. These units are called "must-run" units. In general, the ISO dispatches these units under cost-based contracts regulated by the FERC that allow the owners to recover a portion of fixed and operating costs of the must-run units. Depending on whether an owner operates its must-run units for market sales or, if the unit is uneconomic, will run them only when dispatched by the ISO, the must-run contract pays part or all of the unit's fixed costs, respectively. In either case the must-run contract covers operating costs. The Utility's two remaining fossil-fueled power plants (Hunters Point and Humboldt Bay), and two of its hydroelectric generation facilities, are under must-run contracts. The Utility is paid under this contract for all fixed costs of Hunters Point and for part of the fixed costs of the other facilities. The Utility currently receives approximately $132 million per year as payments under these must-run contracts, plus fuel costs. Because these plants are presently subject to cost-based rate regulation by the CPUC, the Utility does not earn market revenues for these plants when the ISO has not dispatched the plant because they are dispatched to serve the Utility's customers, not when the market would select them. Charges set by the CPUC for Utility retained generation plus the costs paid through the must-run contract are used to meet the costs of those units.

FERC Transmission Owner Rate Case. The ISO controls most of the state's electric transmission facilities. The Utility serves as the scheduling coordinator to schedule transmission with the ISO to facilitate continuing service under wholesale transmission contracts that the Utility entered into before the ISO was established. The ISO bills the Utility for providing certain services associated with these contracts. These ISO charges are referred to as the "scheduling coordinator costs." As part of the Utility's Transmission Owner rate case filed at the FERC, the Utility established a balancing account, the Transmission Revenue Balancing Account (TRBA), to record these scheduling coordinator costs in order to recover these costs through transmission rates. Certain transmission-related revenues collected by the ISO and paid to the Utility are also recorded in the TRBA. Through December 31, 2001, the Utility had recorded approximately $110 million of these scheduling coordinator costs in the TRBA. (The Utility has also disputed approximately $27 million of these costs as incorrectly billed by the ISO. Any refunds that ultimately may be made by the ISO would be credited to the TRBA.) In September 1999, a proposed decision was issued denying recovery of these scheduling coordinator costs. The proposed decision is subject to change by the FERC in its final decision. The FERC is expected to issue a final decision sometime in 2002. On January 11, 2000, the FERC accepted a proposal by the Utility to establish the Scheduling Coordinator Services (SCS) Tariff that would act as a back-up mechanism for recovery of the scheduling coordinator costs if the FERC ultimately decides that these costs may not be recovered in the TRBA. The FERC also conditionally granted the Utility's request that the SCS Tariff be effective retroactive to March 31, 1998, but the FERC suspended the procedural schedule until the final decision is issued regarding the inclusion of scheduling coordinator costs in the TRBA.

AB 1890 Electric Base Revenue Increase . AB 1890 provided for an increase in the Utility's electric base revenues for 1997 and 1998, for enhancement of transmission and distribution system safety and reliability. The CPUC authorized a 1997 base revenue increase of $164 million. For 1998, the CPUC authorized an additional base revenue increase of $77 million. The CPUC will determine how much of the authorized increases were actually spent on system safety and reliability during 1997 and 1998, and adjust the amounts downward if necessary. The Utility claims that it overspent the 1997 authorized revenue requirement by approximately $11.8 million and that it underspent 1998 incremental revenues by approximately $6.5 million. The Utility has proposed that the underspent amount be credited to TRA revenues. In July 1999, **t** he ORA recommended that $88.4 million in expenditures for 1997 and 1998 be disallowed. In August 1999, TURN recommended an additional $14 million disallowance for a total recommended disallowance for 1997 and 1998 expenditures of

$102.4 million. The Utility opposed the recommended disallowances and hearings were held in October 1999. It is uncertain when a proposed decision will be issued by the CPUC. Any proposed decision would be subject to comment by the parties and change by the CPUC before a final decision is issued.

Electric Transmission Rates . Electric transmission revenues, and both wholesale and retail transmission rates are subject to authorization by the FERC. The FERC has not yet acted upon a settlement filed by the Utility that, if approved, would allow the Utility to recover $391 million in electric transmission rates for the 14-month period of April 1, 1998, through May 31, 1999. During that period, somewhat higher rates were collected, subject to refund. A FERC order approving this settlement is expected before the end of 2002. The Utility has accrued $29 million for potential refunds related to the 14-month period ended May 31, 1999. In April 2000, the FERC approved a settlement that permits the Utility to recover $298 million in electric transmission rates retroactively for the 10-month period from May 31, 1999, to March 31, 2000. In September 2000, the FERC approved another settlement that permits the Utility to recover $340 million annually in electric transmission rates and made this retroactive to April 1, 2000. Further, in July 2001, the FERC approved another settlement that permits the Utility to collect $262 million annually (net of the 2002 TRBA) in electric transmission rates. This decrease in transmission rates relative to previous time periods is due to unusually large balances paid to the Utility from the ISO for congestion management charges and other transmission related services billed by the ISO that are booked in the TRBA.

Post-Transition Period Ratemaking Proceeding. In October 1999, the CPUC issued a decision in the Utility's post-transition period ratemaking proceeding. Among other matters, the CPUC decision prohibits the Utility from collecting any costs incurred during the rate freeze but not recovered during the rate freeze, including costs that are not transition costs and not related to generation assets such as under-collected wholesale power purchase costs incurred on behalf of retail distribution customers. In November 2000, the California Supreme Court denied the Utility's petition for review of an appellate decision that had denied the Utility's petition for review of the CPUC's decision. The Utility has filed a complaint against the CPUC in federal court requesting the court to declare that the Utility is permitted as a matter of federal law to recover from distribution customers the wholesale power purchase costs it has incurred to purchase power on their behalf. For more information, see "Item 3—Legal Proceedings" below.

In the October 1999 decision, the CPUC also established the Purchased Electric Commodity Account (PECA) for the Utility to track energy costs after the rate freeze and transition period end. In June 2000, the CPUC issued a decision in which the CPUC determined that the PECA would reflect a pass-through of energy costs, possibly subject to after-the-fact reasonableness reviews. The decision states that after the rate freeze ends, there will be rate proceedings that will, among other matters, address electric energy procurement practices and rates.

Gas Ratemaking

Gas Accord . The Gas Accord separated, or "unbundled," the Utility's gas transmission services from its distribution services, changed the terms of service and rate structure for gas transportation, increased the opportunity for core customers to purchase gas from competing suppliers, established a form of incentive mechanism to measure the reasonableness of core procurement costs, and established gas transmission and storage rates through 2002. In November 2000, the Utility filed an advice letter requesting authorized increases in the rates established for 2001 by the Gas Accord. The Utility has filed an application with the CPUC to extend the Gas Accord for an additional two years. Additional information about the Gas Accord is provided below in "Utility Operations-Gas Utility Operations."

General Rate Case . In February 2000, the CPUC issued a decision in the Utility's GRC for the period 1999 through 2001. The decision is retroactive to January 1, 1999. The CPUC authorized base revenues for the Utility's gas distribution function, including public purpose programs, of approximately $892 million, reflecting an increase of approximately $93 million over base revenues authorized in 1996. Revised gas transportation rates reflecting the revenue changes resulting from the GRC and other regulatory proceedings were effective March 1, 2000. (For a discussion of the 2003 GRC, see "Electric Ratemaking" above.)

The Core Fixed Cost Account (CFCA). The CFCA is the regulatory balancing account that matches gas distribution and storage authorized revenue to the actual revenue collected from core customers.

Gas Procurement Costs . The Utility procures gas for more than 90% of its core customers. The Utility passes on the natural gas costs it incurs on behalf of customers to ratepayers. The core procurement rate is set monthly based on the forecasted cost of gas. Gas procurement activity is recorded in the Purchased Gas Account (PGA). The PGA matches the actual gas commodity costs to the revenue collected from customers. Over- or under-collections in the PGA are collected or returned to customers through an adjustment to the gas procurement rate in subsequent months.

The Biennial Cost Allocation Proceeding (BCAP) . The BCAP remains the proceeding in which distribution costs and balancing account balances are allocated to customers. The BCAP normally occurs every two years and is updated in the interim year for purposes of amortizing any accumulation in the balancing accounts. Balancing accounts for gas distribution and public purpose program revenue requirements accumulate differences between authorized revenue requirements and actual base revenues. In April 2000, the Utility filed its 2000 BCAP application to cover the period January 1, 2000, through December 31, 2002, requesting a decrease in the annual base revenue requirement of $132 million compared to the authorized revenue requirement of $941 million at the time the application was filed. On October 27, 2000, the Utility filed with the CPUC a settlement agreement between the Utility and various parties and groups representing noncore industrial, electric generation, and cogeneration customers. The settlement agreement resolved all issues relating the 2000 BCAP application raised by parties regarding customer throughput, marginal costs, the allocation of balancing account balances, and core and noncore rate design. On November 8, 2001, the CPUC issued a decision approving the settlement agreement. The decision adopted a decrease in annual base revenue requirements of $113 million, effective January 1, 2002.

Public Purpose Programs

Under state law, the Utility is authorized to collect not less than $226 million in a separate nonbypassable charge included in electric and gas rates to fund Utility and other entities' investments in four public purpose programs: (1) cost-effective energy efficiency and energy conservation programs, (2) research, development, and demonstration programs, (3) renewable energy resources programs, and (4) low-income electricity programs, including targeted energy efficiency services and rate discounts. Low-income energy efficiency programs are funded at the level of need, but are not to be funded at less than the 1996 level of expenditures. The Utility is obligated to fund through electric rates energy efficiency and conservation programs in an amount not less than $106 million per year, public interest research and development programs at not less than $30 million per year, renewable energy technologies at not less than $48 million per year, and low-income energy efficiency (LIEE) programs at not less than $14 million per year. Natural gas programs are funded at the level of not less than $13 million for energy efficiency and conservation programs, $15 million for low income energy efficiency programs, and less than $1 million for research and development programs. The Utility also collects funds for the California Alternate Rates for Energy (CARE) low-income discount rate, a rate subsidy paid for by the Utility's other customers, which is currently about $110 million per year.

The CPUC is responsible for allocating the funds for both the cost-effective energy efficiency and LIEE programs. Section 327 of the California Public Utilities Code requires utilities to continue to administer LIEE programs. In November, 2001, the CPUC ordered the utilities to continue to administer statewide energy efficiency programs, and requested competitive bids for local energy efficiency programs (about 35% of the total energy efficiency funding). The CEC administers both the public interest research and development program and the renewable energy program on a statewide basis. The Utility transfers $78 million per year to the CEC for these two programs.

The AEAP determines shareholder incentives to be earned for the Utility's energy efficiency programs. In May 2000, the Utility filed its 2000 AEAP application seeking to recover approximately $53 million of shareholder incentives for attainment of milestones for program year (PY) 1999 energy efficiency programs, and for achieving savings for PY 1998 and 1999 LIEE programs and for energy efficiency accomplishments related to pre-1998 programs. In October 2000, the CPUC postponed the proceedings until further notice. On May 1,

2001, the Utility filed its 2001 AEAP application for recovery of shareholder incentives for attainment of milestones for PY 2000 energy efficiency programs and PY 2000 and 1999 LIEE programs and for shareholder incentives for energy efficiency accomplishments related to pre-1998 programs. On May 9, 2001, the 2000 AEAP and 2001 AEAP applications were consolidated for further proceedings. The total award claim for both the 2000 AEAP and the 2001 AEAP is $80.464 million. A CPUC decision is anticipated during March 2002.

Electric Utility Operations

California Electric Industry Restructuring

The deregulation of California's electric market was implemented beginning in 1998, based on CPUC decisions issued in 1995 and restructuring legislation passed in 1996 (AB 1890). As part of this deregulation, the Utility and the other California investor-owned utilities were strongly encouraged to divest a large portion of their generation assets. In addition, the investor-owned utilities were required to sell their remaining power output into the PX and to buy all of the power requirements of their retail customers from the PX. For the first two years, the wholesale power market created through the restructuring produced prices that were generally less than the generation costs included in retail rates. Based on the resulting net revenues and proceeds received by the Utility from the divestiture of its fossil-fueled and geothermal generation assets, it appeared that the Utility's transition costs would be recovered before March 31, 2002, thus allowing the rate freeze to end sooner than the statutory end date. In fact, the rate freeze ended in mid-1999 for San Diego Gas & Electric Company, one of California's three investor-owned utilities.

Beginning in June 2000, market prices for wholesale electricity in California began to escalate. Prices moderated somewhat in September and October of 2000, only to skyrocket unexpectedly to much higher levels in mid-November and December of 2000. The Utility's revenues from frozen retail rates were insufficient to recover the Utility's cost of purchasing wholesale power for its customers at FERC-approved market-based rates. This created a financial crisis for the Utility and its parent, PG&E Corporation. The Utility's under-collected power purchase costs grew to $6.6 billion at December 31, 2000. The Utility continued to finance the higher costs of wholesale electric power while it worked with interested parties to evaluate various solutions to the energy crisis. In early January 2001, Moody's and S&P, principal credit rating agencies, reduced the Utility's credit ratings. On January 16 and 17, 2001, S&P and Moody's, respectively, again reduced the Utility's credit ratings to below investment grade, precluding further financing for power purchases and resulting in an event of default under the Utility's $850 million revolving credit facility, which left the Utility without available credit lines to pay maturing commercial paper.

Generation Divestiture and Market Valuation . To encourage the California investor-owned utilities to divest at least 50% of their generation assets, the CPUC proposed an increase of up to 10 basis points in the equity return on the undepreciated net book value of fossil-fueled generation assets for each 10% of fossil-fueled generation capacity divested. Moreover, in part to induce the Utility to sell the remainder of its generation assets, the CPUC reduced the return on equity the Utility could earn on any generation asset it did not sell substantially below its otherwise authorized return to a level equivalent to 90% of the Utility's embedded cost of debt (or 6.77%). As a result, the Utility sold virtually all of its fossil-fueled and geothermal generation capacity with CPUC authorization and approval. By January 2000, the Utility owned only its large nuclear power generating facility at Diablo Canyon, its hydroelectric generation facilities and two smaller, older fossil facilities. As the amount of the Utility's own generation resources decreased, the Utility was forced to rely on power supplied by third-party power producers through the PX to meet the needs of its customers.

The structure of the transition to a fully competitive generation market established by AB 1890 also required all of the Utility's generation assets to be market valued, if not through sale, then through appraisal or other divestiture. The CPUC was required by California Public Utilities Code Section 367 to complete market valuation of all generation assets by December 31, 2001. Under AB 1890, once an asset had been market valued, it was no longer subject to rate regulation by the CPUC. The market valuation process was intended to be an

integral and essential step in recovering transition costs and measuring whether the transition period had ended. The transition costs eligible for recovery were to be calculated by netting above-market assets against below-market assets. Once market valuation had occurred, the end of the rate freeze date was to be computed retroactively to the point at which all transition costs had been recovered. To date, the only assets of the Utility that the CPUC has valued have been those that were divested through sale, except with respect to the Utility's Hunters Point power plant which the CPUC ruled had no market value.

The Utility timely submitted proposed market valuations of retained generation facilities, so that those facilities could be valued by the CPUC and released from CPUC regulation. In August 2000, the Utility submitted an interim market valuation of $2.8 billion for its remaining non-nuclear generation facilities. In June and December 2000, the Utility submitted testimony to the CPUC providing a market valuation of its hydroelectric facilities that placed the market value of these facilities at $4.1 billion.

In January 2001, the California Legislature enacted AB 6X, which precludes disposition of utility-owned generating facilities prior to January 1, 2006, but does not repeal the statutory requirement that those assets be market valued by December 31, 2001. On December 21, 2001, the assigned CPUC Commissioner issued a ruling for comment in which she expressed her opinion that the requirement of AB 1890 to market value retained generation by December 31, 2001, had been superseded by State Assembly Bill 6X. On January 15, 2002, the Utility filed its comments on the proposal stating that AB 6X did not relieve the CPUC of its statutory obligation to market value the retained generation by December 31, 2001. In support of its position, the Utility cited a March 7, 2001 filing by the AG that "nothing in AB 6X has changed the requirement for the Commission to determine the market value of the hydroelectric generation assets."

On January 17, 2002, the Utility filed an administrative claim with the State of California Victim Compensation and Government Claims Board (Board) alleging that AB 6X violates the Utility's contractual rights under AB 1890. Pursuant to the regulatory contract established in AB 1890, the Utility divested most of its generating assets to third parties, received a lower than authorized return on the Utility's remaining generating assets, relinquished operating control of its transmission system to the ISO, and opened up its transmission and distribution facilities to competing third party power sellers. The Utility's administrative claim asserts that the State breached the AB 1890 regulatory contract when AB 6X was enacted. The Utility's administrative claim seeks compensation for the denial of the Utility's right to the market value of its retained generating facilities in FERC-regulated interstate power markets and not subject to rate regulation by the CPUC, a value of not less than $4.1 billion. On February 22, 2002, the Board denied the Utility's claim. The Utility has six months from the date of denial to file a suit regarding this claim in California Superior Court.

The Power Exchange, the Independent System Operator, and the Buy/Sell Requirement. To jump start the electric power market in California, AB 1890 provided for the creation of the PX. The PX structure and tariffs were subject to FERC jurisdiction and approval, and PX prices were set by the market pursuant to FERC- authorized tariffs. The PX provided an auction process, intended to be competitive, to establish hourly transparent market clearing prices for electricity in the markets operated by the PX. The PX operated two energy spot markets: the day-ahead market where market participants purchase power for their customers' needs on the following day, and the day-of market where market participants purchase power needed to serve their customers on the same day. The CPUC required the California investor-owned utilities to sell into the PX all of their generated and contracted-for electric power. At the same time, the CPUC required the California investor-owned utilities to buy all of the power needed to serve their retail customers through the PX. This short-term spot market approach represented a dramatic shift from the existing pricing approach based on a portfolio of short- and longer-term contracts. At the time the PX was formed and in several subsequent decisions, the CPUC ruled that prices paid by utilities to the PX under the CPUC's "buy-sell" mandate were presumed to be prudent and reasonable for the purpose of recovery in retail rates.

AB 1890 also created the ISO, as a FERC jurisdictional entity, to exercise centralized operational control of the statewide transmission grid. The Utility and other public utilities were obligated to transfer control, but not ownership, of their transmission systems to the ISO. The ISO is responsible for ensuring the reliability of the transmission grid and keeping momentary supply and demand in balance.

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

AB 1890 also required that the wholesale market structure created by the PX and ISO be competitive and free from market power and market manipulation. On October 30, 1997, the FERC approved the market auction mechanisms of the ISO and the PX. As part of the same order and consistent with the requirements of AB 1890, the FERC directed the ISO and the PX to prescribe mitigation standards to address potential market power. Specifically, the FERC recognized that the California market remained highly concentrated, and that the ability of the PX and ISO mechanisms to restrain market power was unclear. Accordingly, the FERC required that the ISO and PX develop unit availability standards and variable cost-based bid ceilings for each generating unit, as well as a schedule of penalties and defined triggers so that such protections could be imposed as necessary, if market power or manipulation became apparent. Notwithstanding the FERC order, the PX and ISO never developed such measures.

In an attempt to reduce potential price volatility associated with the PX, the Utility applied to the CPUC in 1996 for authority to purchase power outside of the spot markets maintained by the PX and the ISO and to employ financial hedging instruments. The CPUC denied these requests in August 1997. In May 1999, the PX obtained FERC approval to operate the block forward market (BFM). The BFM was an exchange that matched bids to buy a specific amount of power for one month (and later one-quarter and annual terms) with offers to sell power for the same period in advance of the contracted delivery date. In July 1999, the Utility obtained CPUC authority to participate in the BFM. The BFM provided the Utility a limited opportunity to hedge against prices in the PX day-ahead market only; it did not enable the Utility to hedge against ISO real-time market prices.

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

Under the ISO’s tariff, the ISO is allowed to schedule third-party transactions only with creditworthy buyers or creditworthy counterparties. As a result of the early January 2001 credit ratings downgrade, the Utility failed to meet the ISO’s creditworthiness criteria, spelled out in the ISO tariff, for scheduling third-party power transactions through the ISO. On January 4, 2001, the ISO applied to the FERC to modify the creditworthiness standards, which request was opposed by power sellers. On February 14, 2001, the FERC rejected the ISO’s request and ruled that the ISO could not waive the creditworthiness requirement applicable to third-party power purchases. However, the FERC permitted the ISO to continue to schedule power from the Utility so long as it was from the Utility’s own or contracted-for generation to serve the Utility’s retail customers. Despite the ruling, the ISO continued to charge the Utility for the ISO’s third-party power purchases that were made to serve the Utility’s retail customers. These ISO charges contributed to the Utility’s enormous under-collection of procurement costs. On April 6, 2001, the same day that the Utility filed its bankruptcy petition, the FERC issued an order granting a motion filed by several California generators to compel the ISO to comply with the FERC’s February 14, 2001, order, affirming the FERC’s prior conclusion that the ISO tariff did not permit the ISO to make third-party power purchases for parties that failed to meet the tariff’s creditworthiness provisions.

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

The Rate Freeze and Transition Cost Recovery . As required by AB 1890, beginning January 1, 1997, electric rates for all customers were frozen at the level in effect on June 10, 1996, except that rates for residential and small commercial customers were reduced by 10% from their 1996 levels and frozen at that level. In 1997, the Utility, through its wholly owned limited liability company, refinanced the expected 10% rate reduction with $2.9 billion of rate reduction bonds. At December 31, 2001, $1.7 billion of bonds remained outstanding. If the CPUC ultimately determines that the rate freeze ended before December 31, 2001, the Utility may be obligated to return a portion of the economic benefits of the transaction to customers. The timing of any such return and the exact amount of such portion, if any, have not yet been determined.

Under AB 1890, the rate freeze is supposed to end when the investor-owned utility has recovered its eligible "transition" costs (costs of utility generation-related assets and obligations that were presumed to become uneconomic under a competitive generation market structure), but in no event later than March 31, 2002. Based on the presumption that market-based revenues would not be sufficient to recover the utilities' historic generation-related costs, AB 1890 provides the investor-owned utilities a reasonable opportunity to recover their transition costs during this transition period. Under limited circumstances, some transition costs could be recovered after the transition period. Costs eligible for recovery as transition costs, as determined by the CPUC, include (1) above-market sunk costs (i.e., costs associated with utility generating facilities that are fixed and unavoidable and that were included in customer rates on December 20, 1995) and future unavoidable above- market firm obligations, such as costs related to plant removal, (2) costs associated with pre-existing long-term contracts to purchase power at above-market prices from qualifying facilities (QFs) and other power suppliers, and (3) generation-related regulatory assets and obligations.

Transition costs were offset by or recovered through (1) "headroom" (i.e., the amount of revenues collected through frozen rates that remains, if any, after paying authorized operating costs, including power procurement costs), (2) the portion of the market value of generation assets sold by the Utility or market valued by the CPUC that is in excess of book value, and (3) revenues greater than the allowed revenue requirements associated with energy sales from the utilities' remaining electric generation facilities.

In order to track the recovery of the utilities' costs during the rate freeze period, the CPUC established two accounting mechanisms: the Transition Revenue Account (TRA) and the Transition Cost Balancing Account (TCBA). In general, the TRA was used to account for the Utility's revenues from the provision of electric service to retail customers, the Utility's costs of procuring wholesale electricity for resale to retail customers, the costs of operating its electric transmission and distribution system and other operating costs. The TRA recorded PX and ISO charges, transmission rates authorized by the FERC, and distribution and other rates authorized by the CPUC. If those charges and rates for a given month exceeded the Utility's retail revenues, the TRA was "under-collected" for that period. During the same period, the TCBA generally was used to record the Utility's transition costs, the revenues from the wholesale sales of electricity generated by the Utility's retained generation facilities, and the gain on sale (or on market valuation) of the Utility's generation assets in excess of such assets' book

value. Under CPUC rules in effect until the adoption of the retroactive accounting changes in March 2001 (see below), to the extent the Utility's revenues from retail electricity sales exceeded its costs in any given month, the resulting positive balance in the TRA (referred to as "headroom") was transferred on a monthly basis to the TCBA and applied to recover the Utility's transition costs. To the extent revenues from frozen rates were insufficient to cover operating costs recorded in the TRA, the account accumulated an "under-collection," and the under-collection was carried over to the following period for recovery.

In September 2000, the Utility advised the CPUC that, based on a credit to the Utility's TCBA for the above-market estimated market valuation of its hydroelectric generation assets ordered to be made by the CPUC in February 2000, the Utility had recovered its transition costs at least by August 2000, and possibly earlier depending on the final valuation of the hydroelectric assets. In October and November 2000, the Utility again requested the CPUC to lift the rate freeze as required by AB 1890 and the CPUC's prior decisions. Although the CPUC had specifically ruled in October 1999 that the rate freeze would end on the basis of either an estimated or final market valuation, it did not act to grant the Utility's request.

In November 2000, the Utility filed a complaint in federal court against the Commissioners of the CPUC requesting declaratory and injunctive relief compelling the State to recognize the Utility's right to recover in retail rates the costs which it incurred or incurs in the federally regulated wholesale market. The Utility argued that the wholesale power costs which it incurred were paid pursuant to filed rates and tariffs that the FERC authorized and approved and, under the U.S. Constitution and numerous court decisions, such costs could not be disallowed by state regulators, as such actions would be preempted by federal law, unlawfully interfere with interstate commerce, and result in an unlawful taking and confiscation of the Utility's property. For more information about this case, see "Item 3.—Legal Proceedings" below.

On March 27, 2001, the CPUC also adopted a proposal submitted by TURN to change its previously adopted accounting rules governing entries to the TRA, the TCBA, and the generation memorandum accounts. These accounting mechanisms had been adopted by the CPUC in 1998 to account for transition recovery and determine when the rate freeze had ended. In the March 27, 2001, retroactive accounting decisions, the CPUC decided that the Utility should restate its TRA and TCBA, retroactive to January 1, 1998, by transferring on a monthly basis the balance in the Utility's TRA to the Utility's TCBA. Thus, rather than transferring only the monthly "headroom" to pay down transition costs in the months that revenues exceeded the costs of service, the CPUC changed the accounting rules to require the transfer of the monthly balance in the TRA, regardless of whether it was over-collected or under-collected. The effect of this decision was to retroactively restate past recovery of transition costs and apply the headroom against procurement costs, rather than against transition costs. The CPUC also ordered that the utilities restate and record their generation memorandum account balances to the TRA on a monthly basis before any transfer of generation revenues to the TCBA. This meant that any generation revenues in excess of costs were used first to pay wholesale power costs, if any, rather than using those revenues to offset transition costs.

The retroactive transfer of a TRA under-collection has the effect of increasing the amount of transition costs still to be recovered from June 2000 onward. By this retroactive change, the CPUC increased the market valuation of generation assets required to end the rate freeze in the latter part of 2000, ensuring that the previous market valuation recorded by the Utility was no longer sufficient to end the rate freeze in August 2000. The change had the effect of retroactively erasing from the Utility's books and records the evidence that the Utility had previously presented demonstrating that the rate freeze had ended with respect to the Utility.

The Utility filed an application for rehearing of the CPUC's retroactive accounting change alleging that the adoption of the accounting changes violates AB 1890 and the CPUC's authority, constitutes an unconstitutional taking of the Utility's property, violates the Utility's federal and state due process and equal protection rights and constitutes unlawful retroactive ratemaking. Other parties including TURN also filed applications for rehearing. On January 2, 2002, the CPUC granted the applications for rehearing only with respect to the issue of whether the AB 1890 rate freeze should be ended and denied the applications in all other respects. The Utility requested

that the Bankruptcy Court bar the CPUC from requiring the Utility to implement the regulatory accounting changes. On June 1, 2001, the Bankruptcy Court denied the Utility's application for a preliminary injunction. An appeal of the Bankruptcy Court's decision is now pending.

New California Legislation . As the Utility's creditworthiness deteriorated, the Utility was unable to continue financing its wholesale power purchases. On January 17, 2001, the Governor of California signed an order declaring an emergency and authorizing the DWR to purchase power to maintain the continuity of supply to retail customers. On January 19, 2001, the California Legislature passed and the Governor signed Senate Bill 7X which authorized the DWR to purchase electric power for the retail end-use customers of California's investor-owned utilities through January 31, 2001. On February 1, 2001, the California Governor signed Assembly Bill 1X (AB 1X) to authorize the DWR to purchase power and sell that power directly to the utilities' retail end-use customers. AB 1X required the DWR to sell power that it purchases directly to retail end-use customers, except as may be necessary to maintain system integrity. AB 1X also required the Utility to deliver the power purchased by the DWR over its distribution systems and to act as a billing agent on behalf of the DWR, without taking title to such power or reselling it to its customers.

AB 1X initially appropriated approximately $496 million for the DWR's power costs and authorized the DWR to borrow from the State's General Fund in order to finance its power purchases until such borrowings are reimbursed through the DWR's issuance of revenue bonds to finance its power purchase program. AB 1X provides that the appropriation and the bonds are to be repaid from the funds collected from the sales of power and associated payments from retail customers of the utilities.

Furthermore, AB 1X allows the DWR to recover, as a revenue requirement, among other things: (1) amounts needed to pay the principal and interest on bonds issued to finance the purchase of power, (2) amounts necessary to pay for the power and associated transmission and related services, (3) administrative costs, and (4) certain other amounts associated with the program. This may include monies expended for power purchases pursuant to the Governor's emergency proclamation of January 17, 2001. AB 1X authorizes the CPUC to set rates to cover the DWR's revenue requirements (but prohibits the CPUC from increasing electric rates for residential customers who use less power than 130% of their existing baseline quantities) until the DWR has recovered the costs of power it has purchased for retail customers.

All money collected for the power acquired and sold by the DWR under AB 1X or the Governor's January 17, 2001, emergency proclamation by electric utilities "shall constitute property of the department" and is to be segregated from other funds of those corporations and held in trust for the benefit of the DWR until transferred to the DWR.

The DWR has purchased power on the spot market and negotiated long-term power purchase agreements (PPAs) in fulfillment of its procurement obligations pursuant to AB 1X. While the details of these agreements were confidential initially, the DWR made public certain details of the agreements in July 2001. The DWR has continued to enter into additional contracts for which it had previously negotiated agreements in principle. According to information presented by the DWR in late July 2001, its spot purchases and long-term contract costs are estimated to cost retail ratepayers approximately $68 billion over the next 10 years, at average prices ranging between $54 and $269 per megawatt-hour (MWh).

Under the emergency state statute authorizing the DWR to procure and sell power, its revenue requirement may not be recovered from retail customers unless and until the DWR has conducted a review to determine whether the revenue requirement is just and reasonable, and the CPUC has issued a decision implementing the ratemaking for allocation and recovery of the revenue requirement from retail customers. In early May 2001, the DWR submitted its proposed revenue requirement to the CPUC to recover its cost of procuring power for the customers of the Utility, Southern California Edison, and San Diego Gas & Electric Company.

In late July 2001, the DWR filed a revised revenue request for approval at the CPUC, stating that it had determined the revised request to be just and reasonable and requesting immediate approval by the CPUC

without hearings. Over the protests of numerous parties, including the Utility, the CPUC determined that it could implement the DWR revenue requirement request without hearings. In addition, the CPUC issued for public comment a proposed rate agreement, under which the CPUC would agree to implement changes in the DWR's revenue requirement automatically on 30 to 90 days' notice over the next 15 years. Finally, the CPUC proposed to grant the DWR's request that it order the Utility to enter into a servicing agreement to act as the DWR's billing and collection agent for recovery of its costs from retail customers, despite the Utility's protests that the servicing agreement was unreasonable and unfair. On September 10, 2001, the CPUC issued an order requiring that the Utility enter into the servicing agreement as requested by the DWR.

On February 21, 2002, the CPUC approved the DWR's state-wide revenue requirement of $9.045 billion for the two-year period ending December 31, 2002, which amount reflects an approximate $958 million reduction in the DWR's November 5, 2001, revenue requirement request of $10.03 billion. The revenue requirement represents the DWR's total expected expenditures less anticipated proceeds from the DWR's external financings. The CPUC allocated this revenue requirement among the Utility and the other two California investor-owned utilities. The CPUC decision allocates 49.8% of the adopted DWR revenue requirement, or about $4.5 billion, to the Utility for the 2001-2002 period. The allocations are subject to true-up adjustments based on the actual amount of power purchased by the DWR for the respective utility's customers during the 2001-2002 period.

The Utility's petition asking the California Superior Court to order the DWR to hold a public hearing as required by state law before determining whether its power costs are just and reasonable and therefore recoverable from the Utility and its retail customers is currently pending. The DWR's revised revenue requirement also does not resolve issues concerning how the DWR request would be reconciled with the Utility's existing rates, including those for its retained generation facilities.

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

On June 19, 2001, the FERC issued a further order on prospective price mitigation for the wholesale spot markets throughout both California and the Western Systems Coordinating Council (WSCC) that established the current mitigation methodology going forward. Among the features of this current price mitigation methodology are (1) its extension to all hours of the day, (2) the reaffirmation of its requirement that all generators in California offer available generation for sale to the ISO's real-time energy market, (3) the establishment of a single market clearing price in the ISO's spot markets in emergency hours, and (4) the establishment of a maximum market clearing price for spot market sales in all hours. The FERC ordered the mitigation to remain in effect until September 2002. The FERC also established a settlement conference whereby all sellers and buyers in the ISO markets could discuss refunds of any overcharges incurred during prior periods.

From June 25 through July 10, 2001, the FERC's chief administrative law judge conducted settlement negotiations, ordered by FERC, in Washington, D.C., among power generators, officials representing the State of California, and representatives from the California utilities, in an attempt to resolve disputes regarding past power sales. The State, led by the Governor's representative, represented that it and the California utilities are owed $8.9 billion for electricity overcharges by the generators from May 2000 to May 2001. The negotiations did not result in a settlement, but the judge recommended that the FERC conduct further hearings to determine what the power sellers and buyers are each owed. On July 25, 2001, the FERC issued an order establishing a methodology based on replication of a competitive market through determination of the least efficient unit dispatched by the ISO and spot gas price indices to establish a mitigated market price. The mitigated market

price would be used to calculate refunds for certain overcharges after October 2, 2000. (The FERC has asserted that it does not have jurisdiction to order refunds for periods before October 2, 2000.) The FERC also ordered a hearing to consider factual issues relating to implementation of the refund methodology. On December 19, 2001, the FERC issued an order on rehearing of the July 25 order that made some modifications in the July 25 methodology. Based on the December 19 order, the administrative law judge held a prehearing conference and established a revised schedule which provides for hearings on the mitigated prices under the FERC-prescribed methodology to be held March 11 through 15, 2002, and for hearings on refund amounts and resulting amounts owed by various parties to be held June 17 through 21, 2002. Concluding briefs are scheduled to be filed by July 12, 2002, which would enable the administrative law judge to issue findings of fact during August 2002, which would thereafter be considered by the FERC.

On February 13, 2002, the FERC ordered its staff to investigate whether Enron Corporation, or any other entity, manipulated short-term prices for electricity and natural gas in the western United States or otherwise exercised undue influence over wholesale electric prices since January 1, 2000, resulting in potentially unjust and unreasonable rates.

Electric Operating Statistics

At December 31, 2001, the Utility served approximately 4.8 million electric distribution customers.

The following table shows the Utility's operating statistics (excluding subsidiaries) for electric energy sold, including the classification of sales and revenues by type of service. Before August 2000, the Utility was required to buy from the PX all electricity needed to provide service to retail customers that continue to choose the Utility as their electricity supplier.

	2001	2000	1999	1998	1997
Customers (average for the year):					
Residential	4,165,073	4,071,794	4,017,428	3,962,318	3,915,370
Commercial	484,430	471,080	474,710	469,136	465,461
Industrial	1,368	1,300	1,151	1,093	1,121
Agricultural	81,375	78,439	85,131	85,429	86,359
Public street and highway lighting	23,913	23,339	20,806	18,351	17,955
Other electric utilities	5	8	0	14	47
Total	4,756,164	4,645,960	4,599,226	4,536,341	4,486,313
Sales-kWh (in millions):					
Residential	26,920	28,753	27,739	26,846	25,946
Commercial	30,945	31,761	30,426	28,839	28,887
Industrial(1)	16,868	16,899	16,722	16,327	16,876
Agricultural(1)	4,150	3,818	3,739	3,069	3,932
Public street and highway lighting	420	426	437	445	446
Other electric utilities	241	266	167	2,358	3,291
California Department of Water Resources pass-through revenues	(28,640)	—	—	—	—
Total energy delivered	50,904	81,923	79,230	77,884	79,378
Revenues (in thousands):					
Residential	$ 3,364,466	$3,007,675	$2,961,788	$2,891,424	$3,082,013
Commercial	3,925,218	2,693,316	2,837,111	2,793,336	2,932,560
Industrial	1,312,280	509,486	863,951	933,316	1,028,378
Agricultural	520,855	385,961	391,876	350,445	413,711
Public street and highway lighting	59,875	43,403	49,209	51,195	53,183
Other electric utilities	39,420	26,269	16,501	50,166	118,781
Revenues from energy deliveries	9,222,114	6,666,110	7,120,436	7,069,882	7,628,626
California Department of Water Resources pass-through revenues	(2,172,666)	—	—	—	—
Miscellaneous	240,276	194,947	162,105	161,156	(9,439)
Regulatory balancing accounts	36,494	(6,765)	(50,780)	(40,408)	71,441
Operating revenues	$ 7,326,217	$6,854,292	$7,231,761	$7,190,630	$7,690,628

The following table shows certain customer information:

	2001	2000	1999	1998	1997
Selected Statistics:					
Average annual residential usage (kWh)	6,463	7,062	6,905	6,776	6,627
Average billed revenues per kWh (cents per kWh):					
Residential	12.50	10.46	10.68	10.77	11.88
Commercial	12.68	8.48	9.32	9.69	10.15
Industrial(1)	7.78	3.02	5.17	5.72	6.09
Agricultural(1)	12.55	10.11	10.48	11.42	10.52
Net plant investment per customer ($)	2,018	1,969	2,388	2,705	3,027

(1) Beginning April 1998, the sales-kWh and average billed revenues per kWh include electricity provided to direct access customers where the Utility does not collect commodity charges.

Electric Resources

The Utility's sources of generation during 2001 were as follows: 17% from the Utility's hydroelectric assets, 37% from the Utility's nuclear facilities at Diablo Canyon, 2% from the Utility's fossil-fueled plants, and 44% from QFs and other power suppliers.

Until December 15, 2000, the CPUC required the Utility to sell to the PX all of its owned generation, and generation purchased by the Utility under long-term contracts with QFs and other power providers. On December 15, 2000, among other things, the FERC eliminated the requirement that the Utility sell all of its generation into (and buy all of their energy needs from) the PX, but the FERC ordered the Utility to self-schedule all of its owned and contracted-for generation to meet the needs of its customers. The PX suspended the Utility's trading privileges on January 19, 2001, and the PX markets were suspended as of January 31, 2001. In compliance with the December 15, 2000, FERC order, the Utility has been scheduling its own generation and generation purchased under existing contracts with QFs and other power providers. Since January 17, 2001, the remainder of the power needed to serve the Utility's customers has been purchased by the DWR.

Generating Capacity

At December 31, 2001, Pacific Gas and Electric Company's generation facilities, consisting primarily of hydroelectric and nuclear generating plants, had an aggregate net operating capacity of 6,420 MW. Except as otherwise noted below, at December 31, 2001, the Utility owned and operated the following generating plants, all located in California, listed by energy source:

Generation Type	County Location	Number of Units	Net Operating Capacity kW
Hydroelectric:			
Conventional Plants	16 counties in Northern and Central California	107	2,684,100
Helms Pumped Storage Plant	Fresno	3	1,212,000
Hydroelectric Subtotal		110	3,896,100
Steam Plants:			
Humboldt Bay	Humboldt	2	105,000
Hunters Point(1)	San Francisco	1	163,000
Steam Subtotal		3	482,000
Combustion Turbines:			
Hunters Point(1)	San Francisco	1	52,000
Mobile Turbines(2)	Humboldt	2	30,000
Combustion Turbines Subtotal		3	82,000
Nuclear:			
Diablo Canyon	San Luis Obispo	2	2,174,000
Total		118	6,420,100

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

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

The Utility is interconnected with electric power systems in 14 Western states, Alberta and British Columbia, Canada, and Mexico.

Hydroelectric Generation Assets

The Utility's hydroelectric system consists of 110 generating units at 68 powerhouses, including a pumped storage facility, with a total generating capacity of 3,896 MW. The system includes 99 reservoirs, 76 diversions, 174 dams, 184 miles of canals, 44 miles of flumes, 135 miles of tunnels, 19 miles of pipe, and 5 miles of natural waterways. The system also includes 94 contracts for water rights and 163 statements of water diversion and use.

Under AB 1890 all generation assets must be market-valued by December 31, 2001, through appraisal, sale, or other divestiture. In 1999, the Utility filed an application with the CPUC to determine the market value of the Utility's hydroelectric generation facilities and related assets through an open competitive auction similar to the auction process used in the previous sales of the Utility's fossil-fueled and geothermal plants. In November 2000, consultants hired by the CPUC staff issued a Draft Environmental Impact Report (DEIR) reviewing the potential environmental impacts of the proposed auction under the California Environmental Quality Act (CEQA). The DEIR claimed that the Utility's auction proposal and several alternatives would have significant adverse environmental impacts, and that many, but not all, of these adverse impacts could be mitigated.

In January 2001, the CPUC canceled public hearings on the DEIR, citing the enactment of AB 6X which precludes disposition of utility-owned generating facilities prior to January 1, 2006. (AB 1X does not repeal the statutory requirement that those assets be market valued by December 31, 2001.) In February 2001, the Utility filed a motion to suspend the CEQA process given that there was no discretionary action for the CPUC to take following enactment of AB 6X. In the motion, the Utility reserved its rights to assert that AB 6X was unlawful. The Utility further requested that the CPUC proceed with the market valuation process. In March 2001, the Utility submitted extensive comments on the DEIR detailing its inaccurate, legally and factually flawed analytical methods, and incorrect conclusions. Other parties also filed comments. The CPUC has taken no further action to respond to comments, complete, approve, or adopt the DEIR, or establish the market valuation of the Utility's hydroelectric generating assets as required by state law.

On January 18, 2002, a proposed decision was issued which proposes that the hydroelectric assets be placed on cost-of-service ratemaking. On February 1, 2002, the Utility filed comments on this, as well as other, aspects of the proposed decision. It is uncertain what future ratemaking will be applicable to the hydroelectric assets. See "Electric Ratemaking—Retained Generation Ratemaking Proceeding."

Diablo Canyon Nuclear Power Plant

Diablo Canyon consists of two nuclear power reactor units, each capable of generating up to approximately 26 million kilowatt-hours (kWh) of electricity per day. Diablo Canyon Units 1 and 2 began commercial operation in May 1985 and March 1986, respectively. The operating license expiration dates for Diablo Canyon Units 1 and 2 are September 2021 and April 2025, respectively. As of December 31, 2001, Diablo Canyon Units 1 and 2 had achieved lifetime capacity factors of 83% and 85%, respectively.

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

	2002	2003	2004	2005	2006
Unit 1					
Refueling	April		February	October	
Startup	June		March	November	
Unit 2					
Refueling		February	October		May
Startup		March	November		June

Diablo Canyon Ratemaking . Before December 31, 2001, the Utility's sunk costs in Diablo Canyon were recovered from ratepayers through a sunk cost revenue requirement, at a reduced return on common equity equal to 6.77%. (Sunk costs are costs associated with the facility that are fixed and unavoidable.) The Diablo Canyon sunk costs revenue requirement was recoverable as a transition cost through the TCBA. In addition, a performance-based Incremental Cost Incentive Price (ICIP) mechanism was used to recover Diablo Canyon's operating costs and the cost of capital additions incurred after December 31, 1996. The ICIP mechanism established a rate per kWh generated by the facility for the period 1997 through 2001. The ICIP mechanism was originally scheduled to end December 31, 2001.

As originally contemplated by electric industry restructuring, Diablo Canyon generation would be sold at the prevailing market price for power after the transition period ends. Further, pursuant to the 1997 CPUC decision establishing the ICIP, the Utility is required to begin sharing 50% of the net benefits of operating Diablo Canyon with ratepayers beginning after the transition period. In June 2000, the Utility filed an application with the CPUC requesting approval of its proposal for sharing with ratepayers 50% of the post-rate freeze net benefits of operating Diablo Canyon. The net benefit sharing methodology proposed in the Utility's application would be effective at the end of the rate freeze and would continue for as long as the Utility owned Diablo Canyon. Under the proposal, the Utility would share the net benefits of operating Diablo Canyon based on the audited profits from operations, determined consistent with the prior CPUC decision. If Diablo Canyon experiences losses, such losses would be accrued and netted against profits in the calculation of the net benefits in subsequent periods (or against profits in prior periods if subsequent profits are insufficient to offset such losses). Any changes to the net sharing methodology would have to be approved by the CPUC. However, the CPUC has suspended the proceeding to consider the net benefit sharing methodology.

On January 18, 2002, a proposed decision was issued in the Utility's retained generation ratemaking proceeding which proposes that Diablo Canyon be placed on cost-of-service ratemaking. On February 1, 2002, the Utility filed comments on this, as well as other, aspects of the proposed decision. On February 7, 2002, a CPUC Commissioner issued an alternate proposed decision which proposes not to reject benefit sharing for Diablo Canyon, but which would defer consideration of that issue to the pending CPUC proceeding in which the benefit sharing proposal is being addressed. The alternate proposed decision also notes that the ICIP mechanism is tied to recovery of transition costs. It is uncertain what future ratemaking will be applicable to Diablo Canyon.

Nuclear Fuel Supply and Disposal. The Utility has purchase contracts for, and inventories of, uranium concentrates, uranium hexaflouride, and enriched uranium, as well as one contract for fuel fabrication. Based on current Diablo Canyon operations forecasts and a combination of existing contracts and inventories, the requirement for uranium supply will be met through 2004, the requirement for the conversion of uranium to uranium hexaflouride will be met through 2004, and the requirement for the enrichment of the uranium hexaflouride to enriched uranium will be met through 2002, with 50% coverage in 2003 and 2004. The fuel fabrication contract for the two units will supply their requirements for the next six operating cycles of each unit. These contracts are intended to ensure long-term fuel supply, but permit the Utility the flexibility to take advantage of short-term supply opportunities. In most cases, the Utility's nuclear fuel contracts are requirements-based, with the Utility's obligations linked to the continued operation of Diablo Canyon.

Under the Nuclear Waste Policy Act of 1982 (Nuclear Waste Act), the U.S. Department of Energy (DOE) is responsible for the transportation and ultimate long-term disposal of spent nuclear fuel and high-level radioactive waste. Under the Nuclear Waste Act, utilities are required to provide interim storage facilities until permanent storage facilities are provided by the federal government. The Nuclear Waste Act mandates that one or more such permanent disposal sites be in operation by 1998. Consistent with the law, the Utility signed a contract with the DOE providing for the disposal of the spent nuclear fuel and high-level radioactive waste from the Utility's nuclear power facilities beginning not later than January 1998. However, due to delays in identifying a storage site, the DOE has been unable to meet its contract commitment to begin accepting spent fuel by January 1998. Further, under the DOE's current estimated acceptance schedule for spent fuel, Diablo Canyon's spent fuel may

not be accepted by the DOE for interim or permanent storage before 2010, at the earliest. At the projected level of operation for Diablo Canyon, the Utility's facilities are sufficient to store on-site all spent fuel produced through approximately 2006 while maintaining the capability for a full-core off-load. It is likely that an interim or permanent DOE storage facility will not be available for Diablo Canyon's spent fuel by 2006. In December 2001, the Utility filed a request with the NRC for a license to build a dry cask storage system to store spent fuel at Diablo Canyon, pending disposal or storage at a DOE facility.

In July 1988, the NRC gave final approval to the Utility to store radioactive waste from the retired nuclear generating unit Humboldt Unit 3 at the plant before ultimately decommissioning the unit. The Utility has agreed to remove all spent fuel when the federal disposal site is available.

Insurance . The Utility has insurance coverage for property damage and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). NEIL, which is owned by utilities with nuclear generating facilities, provides insurance coverage against property damage, decontamination, decommissioning, and business interruption and/or extra expenses during prolonged accidental outages for reactor units in commercial operation. Under these insurance policies, if the nuclear generating facility of a member utility suffers a loss due to a prolonged accidental outage, the Utility may be subject to maximum retrospective premium assessments of $26 million (property damage) and $9 million (business interruption), in each case per one-year policy period, if losses exceed the resources of NEIL.

The Price-Anderson Act, as amended by Congress in 1988 (Price Act), limits public liability claims that could arise from a nuclear incident to a maximum of $9.5 billion per incident. The Price Act requires that all nuclear utilities share in the payment for nuclear liability claims resulting from a nuclear incident. The Utility has purchased primary insurance of $200 million for public liability claims resulting from a nuclear incident. An additional $9.3 billion of coverage is provided by secondary financial protection required by federal law and provides for loss sharing among utilities owning nuclear generating facilities if a costly incident occurs. If a nuclear incident results in claims in excess of $200 million, the Utility may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident.

Decommissioning . The Utility's estimated total obligation to decommission and dismantle its nuclear power facilities is $1.8 billion in 2001 dollars ($7.8 billion in future dollars). This estimate, which includes labor, materials, waste disposal charges, and other costs, is based on a 1997 decommissioning cost study. A contingency to capture engineering, regulatory, and business environment changes is included in the total estimated obligation. Actual decommissioning costs are expected to vary from this estimate because of changes in the assumed dates of decommissioning, regulatory requirements, and technology, as well as differences in the amount of labor, materials, and equipment needed to complete decommissioning. The estimated total obligation needed to complete decommissioning is recognized proportionately over the license term of each facility.

Nuclear decommissioning costs recovered in rates are placed in external trusts. The funds in these trusts, along with accumulated earnings, will be used exclusively for decommissioning and dismantling the nuclear facilities. The trusts maintain substantially all of their investments in debt and equity securities. All earnings on the funds held in the trusts, net of authorized disbursements from the trusts and management and administrative fees, are reinvested. Monies may not be released from the external trusts until authorized by the CPUC. In December 1997, the CPUC granted the Utility's request for authority to disburse up to $15.7 million from the Humboldt Bay Power Plant decommissioning trusts to finance three partial nuclear decommissioning projects at Humboldt Unit 3. Accordingly, as of December 31, 2001, $9.3 million ($15.7 million less $6.4 million in expected tax benefits) had been disbursed from the Humboldt Unit 3 non-tax-qualified trust to reimburse the Utility for nuclear decommissioning expenses associated with the partial decommissioning projects. The remaining $6.4 million of the approved expenses will be disbursed only if the Internal Revenue Service (IRS) disallows the expected tax benefits. In February 2000, the CPUC granted the Utility's request to disburse an additional amount of up to $7 million from the Humboldt Bay Power Plant decommissioning trusts to explore licensing and permitting of an on-site dry cask storage facility for the spent nuclear fuel that would allow early

decommissioning of Humboldt Unit 3. At December 31, 2001, $2.6 million ($4.3 million project cost less $1.7 million in expected tax benefits) and $0.5 million has been disbursed from the Humboldt Unit 3 non-tax-qualified trust and tax-qualified trust, respectively, to reimburse the Utility for nuclear decommissioning expenses associated with the dry cask storage facility. Additional licensing and permitting activities are continuing.

At December 31, 2001, the Utility had accumulated external trust funds with an estimated liquidation value of $1.3 billion, based on quoted market prices and net of deferred taxes on unrealized gains, to be used for the decommissioning of the Utility's nuclear facilities.

The amount recovered in rates for nuclear decommissioning costs has historically been authorized by the CPUC as part of the GRC. The CPUC considers the trusts' asset levels, together with revised earnings and decommissioning cost assumptions, to determine the amount of decommissioning costs it will authorize in rates for contribution to the trusts. The monies contributed to the decommissioning trusts, together with existing trust fund balances and projected earnings, are intended to satisfy the estimated future obligation for decommissioning costs. In April 2001, the IRS approved a new Schedule of Ruling Amount (SRA) that lowered the annual amount collected through rates to $24 million, effective January 1, 1999. The Utility has proposed to credit to the TRA the annual difference between the previously authorized CPUC cost-of-service amount for nuclear decommissioning of $26.47 million and the lower IRS SRA amount of $24 million. In 2000, the Utility was able to contribute only $14 million to the trusts due to the Utility's liquidity crisis. The Utility has proposed that it credit its TRA with the $10 million difference between the amount of nuclear decommissioning trust contributions collected in rates during 2000 (based on the IRS SRA) and the amount the Utility was able to contribute in 2000. For the year ended December 31, 2001, annual nuclear decommissioning trust contributions collected in rates were $24 million and this amount was contributed to the trusts.

Since January 1, 1998, nuclear decommissioning costs, which are not transition costs, have been recovered through a nonbypassable charge that will continue until those costs are fully recovered. Recovery of decommissioning costs may be accelerated to the extent possible under the rate freeze. The CPUC has established a Nuclear Decommissioning Costs Triennial Proceeding to determine the decommissioning costs and to establish the annual revenue requirement and attrition factors over subsequent three-year periods.

Other Electric Resources

QF Generation and Other Power Purchase Contracts . The Utility is required by CPUC decisions to purchase electric energy and capacity from independent power producers that are qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA). The CPUC required California utilities to enter into a series of QF long-term power purchase agreements (PPAs) and approved the applicable terms, conditions, price options, and eligibility requirements. The PPAs require the Utility to pay for energy and capacity. Energy payments are based on the QF project's actual electrical output and capacity payments are based on the QF project's total available capacity and contractual capacity commitment. Capacity payments may be reduced if the facility does not meet the performance requirements specified in the PPAs.

Most of the PPAs expire on various dates through 2028, though some have no stated expiration date. Deliveries under the PPAs account for approximately 21% of the Utility's 2001 electric energy requirements and no single contract accounted for more than 5% of the Utility's energy needs.

As of December 31, 2001, the Utility had commitments to purchase approximately 5,000 MW of capacity under CPUC-mandated PPAs. Of the 5,000 MW, approximately 4,100 MW are operational. Development of the majority of the balance is uncertain and it is estimated that very few of the remaining contracts will become operational. The 4,100 MW of operational capacity consists of 2,500 MW from cogeneration projects, 700 MW from wind projects, and 900 MW from other projects, including biomass, waste-to-energy, geothermal, solar, and hydroelectric.

Until December 15, 2000, the Utility was required to schedule into the PX all of the electric power generated by QFs and other providers that the Utility is required to purchase under existing contractual commitments. On December 15, 2000, the FERC eliminated this mandatory sell requirement.

In general, before the steep increase in wholesale power prices that began in June 2000, the price for energy payments under QF contracts was higher than the market price. The amount of the contract payment exceeding the market price is recoverable as a transition cost. Under Section 390(c) of the California Public Utilities Code adopted in AB 1890 and implemented by a November 1999 CPUC decision, QFs could make a one-time election to receive energy payments based on the PX day-ahead market clearing price, on an interim basis and subject to true-up, instead of receiving short-run avoided costs energy payments based on the "transition formula" adopted by AB 1890 and set forth in California Public Utilities Code Section 390(b). Those that elected not to exercise this option continued to receive PPA payments based on the Utility's short-run avoided costs. As the wholesale market price of power rose dramatically, many QFs elected to receive PX-based payments, causing the Utility's procurement costs to increase significantly. For the period from June 2000 through January 2001, energy costs for deliveries from QFs who switched to PX pricing were approximately $363 million more than these QFs would have received under the transition formula. On January 10, 2001, the Utility filed an emergency motion with the CPUC requesting that the CPUC true-up payments made to switching QFs since June 2000 to the Utility's "transition formula" short-run avoided cost energy rates or, in the alternative, to PX-based rates capped at $67.45 per MWh. On February 22, 2001, the CPUC issued a decision ordering that QFs that had exercised their one-time option to switch to PX-pricing would be paid short-run avoided cost energy payments based on the transition formula effective on January 19, 2001.

At the end of January 2001, as a result of its inability to borrow and the continued incurrence of excessive procurement costs, the Utility began paying the QFs the pro rata amount the Utility was then recovering in rates to cover its procurement costs, which was approximately 15% of amounts due the QFs. In a decision issued on March 27, 2001, the CPUC ordered the Utility and the other California investor-owned utilities to pay QFs fully for energy deliveries made on and after March 27, 2001, within 15 days of the end of the QFs' billing period. The decision permits QFs to establish a 15-day billing period as compared to the contractual monthly billing period. The CPUC noted that its change to the payment provision was required to maintain energy reliability in California and thus provided that failure to make a required payment would result in a fine in the amount owed to the QF. The decision also adopted a revised pricing formula relating to the California border price of gas applicable to energy payments to all QFs, including those that do not use natural gas as a fuel. Although the revised pricing formula would reduce the Utility's 2001 average QF energy and capacity payments, assuming the differentials between the two gas price indices remained constant, the decision ultimately required the Utility to pay the QFs money it was not then collecting in retail rates, accelerating the Utility's deteriorating financial condition.

As of April 6, 2001, when the Utility filed its bankruptcy petition, the Utility was party to approximately 300 PPAs with various QFs. Almost immediately after the bankruptcy petition was filed, several of the QFs filed motions requesting various forms of relief, including: (1) relief from the automatic stay to permit the QFs to "suspend" deliveries of energy to the Utility and sell into the market, pending the Utility's assumption or rejection of the QF PPAs, (2) an order requiring the Utility to decide immediately whether to assume or reject the PPAs, (3) an order requiring the Utility to pay "market rates" for energy delivered under the PPAs, rather than at the contract rate, and (4) an order requiring the Utility to "pre-pay" for deliveries under the PPAs. In all, approximately 40 QFs ultimately filed motions requesting some or all of the relief described above. The Utility opposed these motions on a number of grounds.

Before the Utility's bankruptcy petition was filed, several QFs filed lawsuits against the Utility for nonpayment. On November 21, 2001, the Bankruptcy Court remanded the claims of one of these QFs, Sierra Pacific Industries, Inc. (SPI), to the Sacramento Superior Court to liquidate SPI's claims. For more information about SPI's claims, see "Item 3—Legal Proceedings" below.

In July 2001, the Utility signed five-year agreements with 197 of its QFs, ensuring that the Utility and its customers receive a reliable supply of electricity at an average energy price of 5.37 cents per kWh. Under the terms of the agreements, the Utility will assume the QF contracts and pay the pre-petition debt on these 197 QF contracts, totaling $845 million, on the effective date of the Plan. The total amount the Utility owed to QFs when

it filed for bankruptcy protection was approximately $1 billion. The agreements represent 85% of debt owed to QFs. For certain of these QFs, if the effective date of the Utility's plan of reorganization has not occurred by July 15, 2003, the Utility will pay 2% of the principal amount of the pre-petition debt per month until the effective date of the plan of reorganization or until July 15, 2005, when it will pay the remaining pre-petition debt. By locking into the average fixed cost, the Utility will help protect its customers from the price fluctuations in the wholesale market. Each of the agreements requires formal approval from the Bankruptcy Court. Most of the agreements have already been approved by the Bankruptcy Court, and the Utility will be making filings for the remainder in the near future.

In December 2001 and January 2002, the Bankruptcy Court approved supplemental agreements entered into between the Utility and approximately 64 of its QFs to resolve the issue of the applicable interest rate to be applied to the pre-petition payables. The supplemental agreements modify the assumption agreements by (1) setting the interest rate for pre-petition payables at 5% per annum, (2) providing for a "catch up payment" of all accrued and unpaid interest (calculated from the date of default through December 31, 2001) that was paid on December 31, 2001, and (3) providing for an accelerated payment of the principal amount of the pre-petition payables (and interest thereon) in 12 equal monthly payments of principal (and interest thereon) commencing on December 31, 2001 (for some QFs payments start on January 31, 2002), and continuing through November 30, 2002, or, in the event the effective date of the plan of reorganization occurs before the last monthly payment is made, the remaining unpaid principal and accrued but unpaid interest thereon, shall be paid in full on the effective date.

The Utility also has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments whether or not any energy is supplied (subject to the supplier's retention of the FERC's authorization) and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. Costs associated with these contracts to purchase power are eligible for recovery by the Utility as transition costs through the collection of the nonbypassable competition transition charge. At December 31, 2001, the undiscounted future minimum payments under these contracts are approximately $32.9 million for each of the years 2002 through 2004 and a total of $247 million for periods thereafter. Irrigation district and water agency deliveries in the aggregate account for approximately 2.8% of the Utility's 2001 electric energy requirements.

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

	2001	2000	1999	1998
Megawatt-hours received	21,019	25,446	25,910	25,994
Energy payments (in millions)	$ 1,454	$ 1,549	$ 837	$ 943
Capacity payments (in millions)	$ 473	$ 519	$ 539	$ 529
Irrigation district and water agency payments (in millions)	$ 54	$ 56	$ 60	$ 53

Bilateral Agreements. The Utility was prohibited, until August 2000, from entering into long-term purchase contracts outside of the PX that would have allowed the Utility to fix its wholesale electricity costs. When the CPUC did grant such authority on August 3, 2000, in response to the Utility's emergency request, prices had already begun to escalate and the CPUC failed to specify the criteria under which such contracts would be deemed reasonable, despite the Utility's request for such criteria and the CPUC's statements that it would establish such criteria. Without reasonableness criteria, the CPUC could second-guess with the benefit of hindsight the Utility's decision to enter into the contracts, and thereby prohibit the Utility from recovering its contract costs from ratepayers.

The CPUC's August 3, 2000, order allowed the Utility to enter into bilateral contracts, subject to previous limits established for BFM purchases (i.e., used to cover the Utility's net open position), provided that all such contracts must expire on or before December 31, 2005. The CPUC's approval of bilateral contracting authority

was subject to agreement on implementation details, such as appropriate pricing benchmarks, with the ORA and the CPUC's Energy Division. The ORA and the Energy Division rejected the Utility's proposed standards and neither has suggested alternative standards.

Despite the lack of established criteria for cost recovery, the Utility entered into several bilateral forward contracts in response to the Utility's solicitation for offers in October 2000. In December 2000, the Utility again solicited offers from power suppliers. However, the Utility received offers from only three bidders, all of which were higher than the forward price curve. Each offer would have immediately triggered the provision for credit requirements, which could have required the Utility to post margins. Furthermore, the CPUC had not adopted, and still has not adopted, criteria for cost recovery of long-term bilateral contracts. Therefore, the Utility did not enter into any additional contracts in response to this second solicitation for offers. The downgrade of the Utility's credit ratings since December 2000 has effectively barred the Utility from entering into additional long-term contracts. In addition to the bilateral agreements entered into in October 2000, the Utility had entered into several short-term (year or less) bilateral agreements.

On December 22, 2000, the CPUC issued a decision requesting comments from interested parties on a set of reasonableness standards proposed in the decision. In this decision, the CPUC proposed price benchmarks which were well below the then current market prices, making it impossible for the Utility to enter into bilateral purchases which the CPUC could deem reasonable. The Utility filed comments to the proposed decision objecting to the proposed standards as unworkable. In January 2001, the CPUC issued another proposed decision adopting similar unrealistic price benchmarks for bilateral purchases. Again, the Utility filed comments expressing its concerns with the new draft decision. It is uncertain whether or when the CPUC will issue appropriate realistic reasonableness standards.

Electric Transmission and Distribution

To transport energy to load centers, Pacific Gas and Electric Company, at December 31, 2001, owned approximately 18,648 circuit miles of interconnected transmission lines of 60 kilovolts (kV) to 500 kV and transmission substations having a capacity of approximately 7,091 megawatt amperes (MVA), including spares, excluding power plant interconnection facilities. Energy is distributed to customers through approximately 116,460 circuit miles of distribution system and distribution substations having a capacity of approximately 24,894 MVA. For the year ended December 31, 2001, the Utility sold 46,818,999 MWh to its bundled retail customers and transported 3,982,112 MWh to direct access customers.

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

In 1998, the FERC approved the forms of agreements for Reliability Must-Run (RMR) generating facilities that have been entered into between RMR facility owners and the ISO to ensure grid reliability and avoid the exercise of local market power. The costs of RMR contracts attributed to supporting the Utility's historic transmission control area are charged to the Utility as a Participating Transmission Owner (PTO). These costs, which were approximately $267 million in 2001, are currently recovered from the Utility's retail customers and, subject to the outcome of current FERC proceedings, wholesale transmission customers.

In March 2000, the ISO filed an application with the FERC seeking to establish its own Transmission Access Charge (TAC) as directed in AB 1890. The FERC accepted the ISO's TAC filing, subject to refund, but suspended the proceeding to allow the parties to enter into settlement discussions. In late December 2000, the ISO made a further implementation filing, also accepted by the FERC subject to refund, to establish specific TAC rates because a transmission-owning municipality had applied to become a new PTO, thereby triggering effectiveness of the ISO TAC rate methodology. The ISO's TAC methodology provides for transition to a

uniform statewide high voltage transmission rate, based on the revenue requirements of all PTOs associated with facilities operated at 200 kV and above. The TAC methodology also requires original PTOs such as the Utility to pay certain increases incurred by new PTOs resulting from joining the ISO during a 10-year transition period. The Utility's obligation for this cost shift is currently capped at $32 million per year.

The Utility has been working closely with the ISO to continue expanding the capacity on the Utility's electric transmission system. One segment of the transmission system proposed to be addressed by the Utility are the transmission facilities known as Path 15, which is located in the southern portion of the Utility's service area, and serves as part of the primary transmission link between Northern and Southern California. At times, the current facilities cannot accommodate all low-cost power intended to be transmitted between Southern California and Northern California. (For transmission purposes, the Diablo Canyon Nuclear Power Plant is located south of Path 15.) This has historically resulted in significant wholesale power price differentials between Northern and Southern California with relatively high power prices in Northern California and relatively low power prices in Southern California. Under a proposal for a joint project coordinated by the U.S. Department of Energy (DOE), presently in the development stages, new transmission facilities would be installed which would substantially increase the capacity of Path 15 in the 2004-2005 timeframe. The Utility expects to be a participant in this project.

The Utility's investment in maintenance and expansion of its transmission system has been growing substantially over the past several years. The Utility made an additional capital investment of approximately $190 million in its transmission system in 2001 and plans to make an additional capital investment of approximately $330 million in its transmission system in 2002. Through the ISO's Long-Term Grid Planning Process, the Utility annually files its transmission upgrade plans and provides the ISO the opportunity to concur with the Utility's planned upgrades.

Gas Utility Operations

Pacific Gas and Electric Company owns and operates an integrated gas transmission, storage, and distribution system in California. The Utility served approximately 3.9 million gas customers at December 31, 2001. Most of these customers continue to obtain gas supplies from the Utility under regulated tariff rates.

The Utility offers transmission, distribution, and storage services as separate and distinct services to its industrial and larger commercial gas (non-core) customers. These customers have the opportunity to select from a menu of services offered by the Utility and to pay only for the services that they use. Access to the transmission system is possible for all gas marketers and shippers, as well as non-core end-users. The Utility's residential and smaller commercial gas (core) customers can select the commodity gas supplier of their choice, but the Utility continues to purchase gas as a regulated supplier for those core customers who do not select another supplier.

At December 31, 2001, the Utility's system consisted of approximately 6,254 miles of transmission pipelines, three gas storage facilities, and approximately 38,410 miles of gas distribution lines. The Utility's Line 400/401 interconnects with PG&E GTN's natural gas transmission system. The PG&E GTN pipeline begins at the border of British Columbia, Canada, and Idaho, and extends through northern Idaho, southeastern Washington and central Oregon, and ends on the Oregon-California border where it connects with the Utility's Line 400/401. The combined Utility-PG&E GTN pipeline provides about 2,700 million cubic feet (MMcf) per day of capacity. More than 1,800 MMf per day can be delivered to Northern and Southern California; and the remaining capacity can be delivered to the Pacific Northwest. The Utility's Line 300, which connects to the U.S. Southwest pipeline systems (Transwestern, El Paso, and Kern River) owned by third parties has a capacity of 1,140 MMcf per day. The Utility's underground gas storage facilities located at McDonald Island, Los Medanos, and Pleasant Creek, have a total working gas capacity of 98 billion cubic feet (Bcf).

The Utility's peak day send-out of gas on its integrated system in California during the year ended December 31, 2001, was 3,793 MMcf. The total volume of gas throughput during 2001 was approximately

368,259 MMcf, of which 270,556 MMcf was sold to direct end-use or resale customers, 11,741 MMcf was used by the Utility primarily for its fossil-fueled electric generating plants, and 85,962 MMcf was transported as customer-owned gas.

The California Gas Report, which presents the outlook for natural gas requirements and supplies for California over a long-term planning horizon, is prepared annually by the California electric and gas utilities. A comprehensive biennial report is prepared in even-numbered years with a supplemental report in intervening odd-numbered years updating recorded data for the previous year.

The 2000 California Gas Report updates the Utility's annual gas requirements forecast (excluding bypass volumes) for the years 2000 through 2020, forecasting average annual growth in gas throughput served by the Utility of approximately 1.4%. The gas requirements forecast is subject to many uncertainties and there are many factors that can influence the demand for natural gas, including weather conditions, level of utility electric generation, fuel switching, and new technology. In addition, some large customers, mostly in the industrial and enhanced oil recovery sectors, may have the ability to use unregulated private pipelines or interstate pipelines, bypassing the Utility's system entirely. The 2002 report is due to be filed July 1, 2002 and will include a new demand forecast along with recorded data for 2001. Recorded data for 2000 was presented in the 2001 report, but that report did not include any new forecasts.

Gas Operating Statistics

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

	2001	2000	1999	1998	1997
Customers (average for the year):					
Residential	3,705,141	3,642,266	3,593,355	3,536,089	3,491,963
Commercial	205,681	203,355	203,342	200,620	198,453
Industrial	1,764	1,719	1,625	1,610	1,650
Other gas utilities	6	6	4	5	3
Total	3,912,592	3,847,346	3,798,326	3,738,324	3,692,069
Gas supply—thousand cubic feet (Mcf) (in thousands):					
Purchased from suppliers in:					
Canada	209,630	216,684	230,808	298,125	280,084
California	10,425	32,167	18,956	17,724	10,655
Other states	76,589	75,834	107,226	122,342	131,074
Total purchased	296,644	324,685	356,990	438,191	421,813
Net (to storage) from storage	(27,027)	19,420	(980)	(14,468)	14,160
Total	269,617	344,105	356,010	423,723	435,973
Pacific Gas and Electric Company use, losses, etc.(1)	(939)	62,960	47,152	129,305	173,789
Net gas for sales	270,556	281,145	308,858	294,418	262,184
Bundled gas sales—Mcf (in thousands):					
Residential	197,184	210,515	233,482	223,706	191,327
Commercial	72,528	66,443	70,093	66,082	60,803
Industrial	831	4,146	5,255	4,616	10,054
Other gas utilities	13	41	28	14	0
Total	270,556	281,145	308,858	294,418	262,184
Transportation only—Mcf (in thousands):					
Vintage system (Substantially all Industrial)(2)	646,079	606,152	484,218	396,872	218,660
PG&E Expansion (Line 401)(3)	0	0	0	0	233,269
Total	646,079	606,152	484,218	396,872	451,929
Revenues (in thousands):					
Bundled gas sales:					
Residential	$ 2,307,677	$ 1,680,745	$ 1,542,705	$ 1,414,313	$ 1,170,135
Commercial	783,080	513,080	448,655	426,299	374,084
Industrial	15,904	35,347	24,638	24,634	46,592
Other gas utilities	2	0	77	1,072	3,701
Bundled gas revenues	3,106,663	2,229,172	2,016,075	1,866,318	1,594,512
Transportation only revenue:					
Vintage system (Substantially all Industrial)	365,550	324,319	267,544	232,038	207,160
PG&E Expansion (Line 401)	9,380	13,392	19,091	42,194	90,180
Transportation service only revenue	374,930	337,711	286,635	274,232	297,340
Miscellaneous	(92,531)	84,526	(47,311)	41,364	50,295
Regulatory balancing accounts	(253,476)	131,762	(259,648)	(448,351)	(137,787)
Operating revenues	$ 3,135,586	$ 2,783,171	$ 1,995,751	$ 1,733,563	$ 1,804,360

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

(2) Does not include on-system transportation volumes transported on the PG&E Expansion of 259 MMcf, 4,833 MMcf, 1,251 MMcf, 34,169 MMcf, and 72,958 MMcf for 2001, 2000, 1999, 1998, and 1997, respectively.
(3) Starting in 1998, Vintage system and PG&E Expansion are combined and reported as total transportation service.

	2001	2000	1999	1998	1997
Selected Statistics:					
Average annual residential usage (Mcf)	53.2	59	65	63	55
Heating temperature—% of normal (1)	105.1	101.2	108.5	93.0	71.7
Average billed bundled gas sales revenues per Mcf:					
Residential	$ 11.70	$ 7.98	$ 6.61	$ 6.32	$ 6.12
Commercial	10.80	7.72	6.40	6.45	6.15
Industrial	19.15	8.53	4.69	5.36	4.63
Average billed transportation only revenue per Mcf:					
Vintage system	0.56	0.54	0.66	0.66	0.71
PG&E Expansion (Line 401)	1.78	2.04	0.53	0.54	0.39
Net plant investment per customer (2)	$ 970	$ 1,003	$ 1,011	$ 1,040	$ 1,031

(1) Over 100% indicates colder than normal.

Natural Gas Supplies

The objective of Pacific Gas and Electric Company's Gas Procurement Department is to maintain a balanced supply portfolio that provides supply reliability and contract flexibility, minimizes costs, and fosters competition among the Utility's gas suppliers. To ensure a diverse and competitive mix of natural gas to serve the Utility's customers, the Utility purchases gas directly from producers and marketers in both Canada and the United States.

Due to the Utility's deteriorating financial condition resulting from the dysfunctional California wholesale power market, in December 2000 and January 2001, several gas suppliers demanded prepayment, cash on delivery, or other forms of payment assurance before they would deliver gas, instead of the normal payment terms under which the Utility would pay for the gas after delivery. As the Utility was unable to meet such demands at that time, several gas suppliers refused to supply gas, thereby accelerating the depletion of the Utility's gas storage reserves, and potentially accelerating the electric power crisis if the Utility were required to divert gas from industrial users, including natural gas-fired power plant operators.

The Utility tried to mitigate the worsening supply situation by withdrawing more gas from storage and, when able, purchasing additional gas on the spot market. Additionally, on January 31, 2001, the CPUC authorized the Utility to pledge its gas account receivables and its gas inventories for up to 90 days (subsequently extended to 180 days and expiring on May 1, 2002) to secure gas for its core customers. More importantly, the Utility currently has a program to obtain summer and winter supplies under accelerated payment terms to alleviate supplier concerns of Utility creditworthiness connected with the bankruptcy. This accelerated payment program combined with the gas receivable securitization program has been successful in securing gas supplies for the near term.

Under current CPUC regulations, the Utility purchases natural gas from its various suppliers based on economic considerations, consistent with regulatory, contractual, and operational constraints. During the year ended December 31, 2001, (i) approximately 71% of the Utility's total purchases of natural gas consisted of Canadian-sourced gas transported by Canadian pipeline companies and PG&E GTN, and Rocky Mountain-sourced gas transported by PG&E GTN, (ii) approximately 4% was purchased in California, (iii) approximately 25% was purchased in the U.S. Southwest and was transported primarily by the Transwestern Pipeline Company pipelines, and (iv) less than 1% was purchased in the Rocky Mountains and transported by Kern River Gas Transmission Company. California purchases include supplies from various California producers and supplies

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

	2001		2000		1999		1998		1997	
	Thousands of Mcf	Avg. Price(1)	Thousands of Mcf	Avg. Price (1)	Thousands of Mcf	Avg. Price (1)	Thousands of Mcf	Avg. Price (1)	Thousands of Mcf	Avg. Price (1)
Canada	209,630	$ 4.43	216,684	$4.05	230,808	$2.50	298,125	$2.00	280,084	$1.77
California	10,425	$16.68	32,167	8.20	18,956	2.45	17,724	2.44	10,655	2.12
Other states (substantially all U.S. Southwest)	76,588	10.41	75,835	5.99	107,227	2.42	122,342	2.62	131,074	3.75
Total/Weighted Average	296,644	$ 6.40	324,686	$4.92	356,991	$2.47	438,191	$2.19	421,813	$2.39

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

Gas Regulatory Framework

In August 1997, the CPUC approved the Gas Accord, which restructured the Utility's gas services and its role in the gas market. Among other matters, the Gas Accord separates, or "unbundles" the rates for the Utility's gas transmission services from its distribution services. As a result of the Gas Accord, the Utility's customers may buy gas directly from competing suppliers and purchase transmission-only and distribution-only services from the Utility. Most of the Utility's industrial and larger commercial customers (noncore customers) now purchase their gas from marketers and brokers. Substantially all residential and smaller commercial customers (core customers) buy gas as well as transmission and distribution services from the Utility as a bundled service. Customer rates for gas are updated on a monthly basis to reflect changes in the Utility's gas procurement costs.

The Gas Accord also established an incentive mechanism (the core procurement incentive mechanism or CPIM) for recovery of the Utility's core gas procurement costs in rates through 2002. The CPIM provides the Utility with a direct financial incentive to procure gas and transportation services at the lowest reasonable costs. Under the CPIM, all Utility procurement costs are compared to an aggregate market-based benchmark. If costs fall within a range (tolerance band) around the benchmark, costs are deemed reasonable and fully recoverable from ratepayers. If procurement costs fall outside the tolerance band, the Utility's ratepayers and shareholders share savings or costs, respectively. The Utility has recovered all gas costs through October 31, 1999. In February 2001, the Utility filed a CPIM performance report for the period November 1, 1999, through October 31, 2000. The report determined that all gas commodity and transportation costs for the period are within the tolerance band, and therefore should be deemed reasonable and recoverable in full from ratepayers.

The Gas Accord also established gas transmission and storage rates for the period from March 1998 through December 31, 2002. Rates for gas distribution service continue to be set by the CPUC in BCAP proceedings, and are designed to provide the Utility an opportunity to recover its costs of service and include a return on investment. See "Utility Operations—California Ratemaking Mechanisms—Gas Ratemaking—The Biennial Cost Allocation Proceeding (BCAP)" above.

On October 9, 2001, the Utility filed a Gas Accord II Application with the CPUC, requesting a two-year extension, without modification, of the existing Gas Accord. This filing was made in response to a recent CPUC order which directed the Utility to file a Gas Accord II application. Under the Utility's proposal, those provisions of the Gas Accord currently scheduled to expire on January 1, 2003, will be extended through December 31,

2004, while certain storage-related provisions scheduled to expire on April 1, 2003, will be extended through March 31, 2005. No change in the previously approved rates in effect as of December 2002 or, in the case of certain storage provisions, as of March 31, 2003, is proposed. The Utility believes the two-year extension that has been proposed will allow for resolution of many uncertainties affecting gas markets today, including the Utility's proposed plan of reorganization. It is uncertain when the CPUC will act on the Utility's proposal.

Transportation Commitments

The Utility has gas transportation service agreements with various Canadian and interstate pipeline companies. These agreements include provisions for payment of fixed demand charges for reserving firm capacity on the pipelines. The total demand charges that the Utility will pay each year may change due to changes in tariff rates. The total demand and volumetric transportation charges paid by the Utility under these agreements were approximately $239 million, $94 million, and $97 million in 2001, 2000, and 1999, respectively. These amounts include payments made by the Utility to PG&E GTN of approximately $41 million, $46 million, and $47 million, in 2001, 2000, and 1999, respectively, which are eliminated in the consolidated financial statements of PG&E Corporation.

As a result of regulatory changes, particularly the Gas Accord, the Utility no longer procures gas for most of its industrial and larger commercial (noncore) customers, resulting in a decrease in the Utility's need for firm transportation capacity on these pipelines. Despite these changes, the Utility continues to procure gas for substantially all of its residential and smaller commercial (core) customers, and noncore customers who choose bundled service. To the extent that the Utility's current capacity holdings exceed demand for gas transportation by its customers, the Utility actively brokers such excess capacity.

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

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

PG&E NATIONAL ENERGY GROUP

PG&E NEG is an integrated energy company with a strategic focus on power generation, natural gas transmission, and wholesale energy marketing and trading in North America.

Natural Gas Transmission Business

Within PG&E Pipeline, PG&E NEG owns, operates and develops natural gas pipeline facilities, including the Gas Transmission Northwest, or PG&E GTN pipeline, an interest in the Iroquois pipeline and the North Baja pipeline.

Gas Transmission Northwest. The PG&E GTN pipeline consists of over 1,350 miles of natural gas transmission pipeline with a capacity of approximately 2.7 Bcf of natural gas per day. The PG&E GTN pipeline begins at the British Columbia-Idaho border, extends for approximately 612 miles through northern Idaho, southeastern Washington and central Oregon, and ends at the Oregon-California border, where it connects with the Utility's pipelines. This pipeline commenced commercial operation in 1961 and has subsequently expanded various times through 2001. This pipeline is the largest transporter of Canadian natural gas into the United States and is the only pipeline directly linking the natural gas reserves in western Canada to the gas markets of California and parts of the Pacific Northwest.

PG&E GTN provides firm and interruptible transportation services to third party shippers on a nondiscriminatory basis. Firm transportation services means that the customer has the highest priority rights to

ship a quantity of gas between two points for the term of the applicable contract. During 2001, 95.2% of PG&E GTN's available long-term capacity was committed to firm transportation services agreements with terms in excess of one year. At December 31, 2001, 99.6% of PG&E GTN's available long-term capacity was held under long-term firm transportation agreements. The terms of these long-term firm contracts range between one and 24 years, with a volume-weighted average remaining term of approximately 12 years at December 31, 2001. PG&E GTN also offers short-term firm and interruptible transportation services plus hub services, which allow customers the ability to park or lend volumes of gas on its pipeline. If weather, maintenance schedules and other conditions allow, additional firm capacity may become available on a short-term basis. PG&E GTN provides interruptible transportation service when capacity is available. Interruptible capacity is provided first to shippers offering to pay the maximum rate and, if necessary, allocated on a pro-rata basis to shippers offering to pay the maximum rate. If capacity remains after maximum tariff nominations are fulfilled, GTN allocates discounted and/or negotiated interruptible space on a highest to lowest total revenue basis.

At December 31, 2001, PG&E GTN provided transportation services for 88 customers, 44 of which had long-term firm transportation agreements with PG&E GTN. The remaining customers utilize hub services or short-term firm, interruptible or capacity release contracts. PG&E GTN customers are principally local retail gas distribution utilities, electric generators that use natural gas to generate electricity, natural gas marketing companies that purchase and resell natural gas to utilities and end-use customers, and industrial companies. PG&E GTN's customers are responsible for securing their own gas supplies and delivering them to the pipeline system. PG&E GTN transports customers' natural gas supplies either to downstream pipelines and distribution companies or directly to points of consumption.

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

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

North Baja Pipeline. GTC's subsidiary, North Baja Pipeline, LLC (NBP), is developing an approximately 80-mile natural gas pipeline, with an initial certificated capacity of 5000 MMcf per day, to be located in Arizona and southeastern California and is expected to cost approximately $146 million. This new pipeline will deliver natural gas to a pipeline being developed by Sempra Energy International. The 135-mile Sempra pipeline will interconnect with NBP at the California-Mexico border and transport gas into Northern Mexico and Southern California. NBP has entered into a joint development agreement with Sempra to coordinate development

activities. On January 16, 2002, the FERC issued a certificate of public convenience and necessity authorizing NBP to construct and operate the proposed pipeline. NBP plans to begin construction of the North Baja pipeline, which will run from Arizona to northern Mexico, in the first quarter of 2002. NBP is projected to be in partial service in the third quarter of 2002 and full service in the fourth quarter of 2002.

NBP has signed agreements with five customers to transport up to 92% of the initial projected daily capacity in 2002 and 2003, and 100% of the initial capacity in 2004 and beyond. Of this amount, approximately 47 MMcf per day is under a contract with one of PG&E NEG's subsidiaries. The weighted average term of these agreements is in excess of 20 years. NBP is continuing discussions and negotiations with other potential customers and working with Sempra Energy International on the possibility of an expansion.

Integrated Energy and Marketing Business

Within PG&E Energy, PG&E NEG engages in the generation, transport, marketing and trading of electricity, various fuels, and other energy-related commodities throughout North America. During the year ended December 31, 2001, PG&E NEG sold approximately 280 million MWh of power, 21.5 Bcf of natural gas (including financial transactions) and 15 million tons of coal.

PG&E NEG aggregates electricity and related products from its owned, leased, or controlled generating facilities and its marketing and trading positions, and manages the fuel supply and sale of electrical output from all these positions in an integrated portfolio. The objective of the integrated approach is to enable efficient management of PG&E NEG's exposure to commodity price and counterparty credit risk. At December 31, 2001, PG&E NEG had ownership or leasehold interests in 25 operating generating facilities with a net generating capacity of 6,518 MW, as follows:

Number of Facilities	Net MW	Primary Fuel Type	% of Portfolio
10	2,997	Coal/Oil	45
10	2,277	Natural Gas	36
3	1,166	Water	18
2	78	Wind	1
25	6,518		100

In addition, PG&E NEG has seven facilities totaling 5,430 MW in construction and controls, through various arrangements, 581 MW in operation, and 2,313 MW in construction, with a total owned and controlled generating capacity in operation or construction of 14,842 MW. PG&E NEG may sell selected operating assets and has identified three of its New England facilities for possible sale. PG&E NEG has established a 2002 target of at least $250 million of after-tax proceeds from the sale of operating and development assets. PG&E NEG also has approximately 6,000 MW of natural gas-fired projects in development.

PG&E NEG's generating facilities can be divided into two categories based on the method of sale of their electric output. The first category is generating facilities that sell all or a majority of their electrical capacity and output to one or more third parties under long-term PPAs tied directly to the output of that plant. These generating facilities are generally referred to as "independent power projects." The second category is generating facilities that sell their electrical output in the competitive wholesale electric market or under contractual arrangements of various terms. These generating facilities are generally referred to as "merchant plants."

All of the generating facilities PG&E NEG developed or placed in operation before 1997 are independent power projects, while almost all those acquired, placed in operation, or acquired control through contracts during or after 1997, are merchant plants. Most of PG&E NEG's generating facilities under construction or development are generally expected to be operated as merchant plants.

Independent Power Projects. PG&E NEG holds its interests in independent power projects through wholly owned subsidiaries. PG&E NEG had a net ownership interest of 1,163 MW in independent power projects at December 31, 2001. Typically, PG&E NEG operates and manages these facilities through an operation and maintenance agreement and/or a services agreement. These agreements generally provide for management, operations, maintenance, and administration for day-to-day activities, including financial management, billing, accounting, public relations, contracts, reporting, and budgets. In order to provide fuel for its independent power projects, natural gas and coal supply commitments are typically purchased from third parties under long-term supply agreements.

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

Merchant Power Plants. PG&E NEG currently owns or has committed to lease or acquire 13 merchant plants under construction in six states that will result in an owned or leased merchant power plant portfolio that will have a net generating capacity of approximately 10,701 MW. These projects are expected to be placed in service in 2002 and 2003. PG&E NEG considers a generating facility to be under construction once PG&E NEG or the lessor has acquired the necessary permits to begin construction, executed a construction contract, delivered an unqualified notice to commence construction and broken ground at the project.

PG&E NEG manages the sale of the electric output from its merchant plants through integrated teams that include marketing, trading, and plant operating personnel. This approach enables PG&E NEG to vary the output of, and fuel used in, PG&E NEG's generating facilities in response to constantly changing regional power demand and prices. PG&E NEG generally does not sell the output of a specific merchant plant to a specific customer but rather combines the output of merchant plants with market purchases of electricity to increase the reliability of, and provide customers and fuel suppliers with, flexible power products.

Contractual Control of Generating Capacity. PG&E NEG has increased its generating capacity through contractual control of the electric output of generating facilities. PG&E NEG has executed various long-term contracts representing 2,831 MW of generating capacity, which result in control of 581 MW of operating generating capacity and 2,313 MW of generating capacity in construction at December 31, 2001. These contracts include control of all or a portion of the output of 16 smaller generating facilities through arrangements with New England Power Company ("NEPCo"), directly with the facilities or through other arrangements. In return for PG&E NEG's assumption of the purchase obligations under these agreements, NEPCo has agreed to pay to PG&E NEG an average of $111 million per year through January 2008, to offset PG&E NEG's payment obligations under these contracts.

Apart from the contracts with NEPCo, PG&E NEG's primary method of achieving contractual control of generating capacity is through tolling agreements. Tolling agreements establish a contractual relationship that grants PG&E NEG the right to use a third party's generating facility to convert PG&E NEG's fuel, typically natural gas, to electricity. PG&E NEG has the right to decide the timing and amount of electricity production within agreed operating parameters. The owner of the facility receives a fixed capacity payment for the committed availability of its facility and a variable payment for production costs. The fixed payment is subject to reduction if the owner fails to meet specified targets for facility availability and other operating factors.

The terms of the five tolling agreements PG&E NEG has in its portfolio at December 31, 2001 range from 9 to 25 years commencing on the date of initial commercial operations of the generating facility. Most of the generating facilities are under construction with commercial operations expected to commence between 2002 and 2004. These tolling agreements provide PG&E NEG with control of gas-fired plants in the Mid-Atlantic, Midwestern, Southern, and Western regions of the United States.

Description of Generating Facilities in Operation and Construction

The following table provides information regarding each of PG&E NEG's owned or controlled operating generating facilities, as well as those under construction at December 31, 2001:

Generating Facility	State	Total MW(1)	Net Interest in Total MW(2)	Structure	Fuel	Primary Output Sales Method	Status	Date of Commercial Operation
New England Region								
Brayton Point Station	MA	1,599	1,599	Owned	Coal/Oil	Competitive Market	Operational	1963-1974
Salem Harbor Station	MA	745	745	Owned	Coal/Oil	Competitive Market	Operational	1952-1972
Bear Swamp Facility	MA	599	599	Leased	Water	Competitive Market	Operational	1974
Manchester St Station	RI	495	495	Owned	Natural Gas	Competitive Market	Operational	1995
Connecticut River System	NH/VT	484	484	Owned	Water	Competitive Market	Operational	1909-1957
Millennium	MA	360	360	Owned	Natural Gas	Competitive Market	Operational	2001
MASSPOWER	MA	267	35	Owned	Natural Gas	Power Purchase Agreements	Operational	1993
Pittsfield(3)	MA	173	140	Leased	Natural Gas	Power Purchase Agreements and Competitive Market	Operational	1990
Milford Power(3)	MA	171	96	Contract	Natural Gas	Competitive Market	Operational	1994
Deerfield River System	MA/VT	83	83	Owned	Water	Competitive Market	Operational	1912-1927
Pawtucket Power(3)	RI	69	69	Contract	Natural Gas	Competitive Market	Operational	1991
14 smaller facilities(3)	Various	193	193	Contract	Renewable/ Waste	Competitive Market	Operational	Various
Lake Road	CT	840	840	Leased	Natural Gas	Competitive Market	Construction	2002
Subtotal		6,078	5,738					
Mid-Atlantic and New York Region								
Selkirk	NY	345	145	Owned	Natural Gas	Power Purchase Agreements and Competitive Market	Operational	1992
Carneys Point	NJ	269	135	Owned	Coal	Power Purchase Agreements	Operational	1994
Logan	NJ	225	113	Owned	Coal	Power Purchase Agreement	Operational	1994
Northampton	PA	110	55	Owned	Waste Coal	Power Purchase Agreements	Operational	1995
Panther Creek	PA	80	40	Owned	Waste Coal	Power Purchase Agreement	Operational	1992
Scrubgrass	PA	87	44	Owned	Waste Coal	Power Purchase Agreement	Operational	1993
Madison	NY	12	12	Owned	Wind	Competitive Market	Operational	2000
Liberty Electric	PA	568	568	Contract	Natural Gas	Competitive Market	Construction	2002
Athens	NY	1,080	1,080	Owned	Natural Gas	Competitive Market	Construction	2003
Subtotal		2,776	2,192					
Midwest Region								
Georgetown	IN	240	160	Contract	Natural Gas	Competitive Market	Operational	2000
Ohio Peakers	OH	144	144	Owned	Natural Gas	Competitive Market	Operational	2001
Covert	MI	1,170	1,170	Owned	Natural Gas	Competitive Market	Construction	2003
Smithland (4)	KY	16	16	Own	Water	Competitive Market	Construction	2003
Subtotal		1,570	1,490					
Southern Region								
Indiantown	FL	360	126	Owned	Coal	Power Purchase Agreement	Operational	1995
Cedar Bay	FL	269	135	Owned	Coal	Power Purchase Agreement	Operational	1994
Attala	MS	526	526	Owned	Natural Gas	Competitive Market	Operational	2001
Southaven	MS	810	810	Contract	Natural Gas	Competitive Market	Construction	2003
Caledonia	MS	810	810	Contract	Natural Gas	Competitive Market	Construction	2003
Subtotal		2,775	2,407					
Western Region								
Spencer	TX	178	178	Owned	Natural Gas	Competitive Market	Operational	1955-1972
Hermiston	OR	474	237	Owned	Natural Gas	Power Purchase Agreement	Operational	1996
San Diego Peakers	CA	80	80	Owned	Natural Gas	Competitive Market	Operational	2001
Mountain View	CA	66	66	Owned	Wind	Power Purchase Agreement	Operational	2001
Colstrip	MT	40	5	Owned	Waste Coal	Power Purchase Agreement	Operational	1990
La Paloma	CA	1,121	1,121	Lease	Natural Gas	Competitive Market	Construction	2002
Plains End	CO	111	111	Owned	Natural Gas	Power Purchase Agreement	Construction	2002
Harquahala	AZ	1,092	1,092	Owned	Natural Gas	Competitive Market	Construction	2003
Otay Mesa	CA	500	125	Contract	Natural Gas	Competitive Market	Construction	2004
Subtotal		3,662	3,015					
Total		16,845	14,842					

(1) Megawatts for owned facilities are based on nominal MW, defined as typical new and clean output at 59 degrees Fahrenheit at sea level. Megawatts for contract-based output are based on the quantities stated in the contracts.

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

(3) PG&E NEG controls all or a portion of the output of these 14 smaller generating facilities, together with the Milford Power Project, the Pawtucket Power Project, and 113 MW from the Pittsfield Project, under long-term power purchase agreements. In return for PG&E NEG's assumption of the purchase obligations under these agreements from NEPCo, NEPCo has

agreed to pay an average of $111 million per year through January 2008, to offset the payment obligations under these contracts. The power purchase agreements terminate between 2009 and 2029. Effective February 1, 2002, PG&E NEG's arrangement with the Pawtucket Power Project was replaced with a system power supply arrangement with an affiliate of Pawtucket Power. PG&E NEG has a leased beneficial interest in the Pittsfield project, 50 MW of which is included in the 113 MW referenced above. An additional 27 MW of PG&E NEG's interest are sold under other long-term power purchase agreements.

(4) PG&E NEG has executed construction contracts for up to 163 MW at two hydroelectric facilities on the Ohio River in Kentucky. The first 16 MW unit is under construction. PG&E NEG's obligation to fund the remaining units is contingent upon the commencement of successful operations of this first unit in 2003.

Greenfield Development

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

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

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

Development has largely been completed for PG&E NEG's Mantua Creek project and it is ready to begin construction. PG&E NEG has entered into a construction contract for the facility and released the contractor to perform a limited amount of early construction activities. At December 31, 2001, PG&E NEG had recorded assets of $168 million for Mantua Creek, representing equipment payments, construction activities and development costs. In light of the current market outlook, PG&E NEG is planning to delay construction of this facility for at least 12 months. PG&E NEG has commenced negotiations with its construction contractor and other parties to the project to address this delay. If PG&E NEG is unable to reach agreement with these parties, or if PG&E NEG decides to abandon the project, PG&E NEG will be required to write-off approximately $110 million of capitalized and termination costs. This amount does not include major equipment costs.

Equipment Procurement

To support PG&E NEG's development program, PG&E NEG has contractual commitments and options for combustion turbines and related equipment representing approximately 14,000 MW of net generating capacity, including the 3,868 MW identified in Greenfield Development above. The following table describes the turbines for which PG&E NEG has contractual commitments or options to use in its development projects:

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

(1) Approximate baseload and peaking/intermediate capacity based on anticipated configuration of the turbine.

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

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

Generally, each of PG&E NEG's equipment supply contracts allows PG&E NEG to cancel any or all of its commitments to purchase the equipment for a predefined cost. To date, PG&E NEG has not cancelled any of its equipment commitments or options. PG&E NEG continues to work with its vendors to defer payments, delay increases of termination fees and revise equipment delivery dates. PG&E NEG has good relationships with its vendors and has, to date, been largely successful in these efforts. However, PG&E NEG is not certain it will continue to be able to modify these agreements to minimize its Termination Costs and match equipment deliveries with its evolving development plans. PG&E NEG's estimates of its exposure for Termination Costs are, in part, based upon current contractual arrangements and amendments thereto which PG&E NEG is confident will be implemented.

At December 31, 2001, PG&E NEG's aggregate Termination Costs for its entire development program other than Mantua Creek were $247 million, and are estimated to increase to $254 million at December 31, 2002, and $368 million at December 31, 2003. PG&E NEG has recorded $221 million (excluding Mantua Creek) of prepayments for equipment on its December 31, 2001 balance sheet.

PG&E NEG is currently marketing four of its development projects for potential sale. If PG&E NEG finds a buyer that is willing to purchase equipment, which may be used with a purchased project, and able to comply with the conditions in its equipment contracts, PG&E NEG can avoid paying termination costs. However, PG&E NEG can not assure that PG&E NEG will be successful in selling any or all of these projects or that the buyers will be able or willing to undertake PG&E NEG equipment purchase obligations.

Turbine Technology

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

Two of the suppliers of G technology turbines have encountered problems in their initial commercial installations of these turbines. The Lake Road and La Paloma facilities are being constructed by Alstom Power, Inc. (Alstom). Alstom has advised PG&E NEG that it may take up to three years to develop and implement modifications to its G technology turbines that are necessary to achieve the guaranteed level of efficiency and output. PG&E NEG expects that the Lake Road and La Paloma facilities will begin commercial operations at reduced performance and output levels because of the technology issues with Alstom's G technology turbines.

PG&E NEG also encountered start-up problems with the Siemens Westinghouse G technology installed in its Millennium facility. These problems delayed the original date of commercial operations for this facility, which began commercial operations in April 2001. Commercial operations commenced pursuant to a settlement among Millennium, Bechtel and Siemens which, among other things, deferred fuel oil commissioning and testing. The facility has not yet demonstrated satisfactory performance using fuel oil and availability has been hampered by continuing new technology issues. PG&E NEG does not expect that the start-up and initial operations problems with the Siemens Westinghouse G technology turbine installed at the Millennium facility will result in a long-term reduction of performance below guaranteed levels of efficiency or output. The construction contracts for each of the Millennium, Lake Road, and La Paloma projects provide for liquidated damages that PG&E NEG believes could significantly offset, but not fully, the financial impact associated with the delays of these turbines in achieving their expected level of performance.

Construction Issues

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

Energy Marketing and Trading

PG&E NEG engages in the marketing and trading of electric energy, capacity and ancillary services, fuel and fuel services such as pipeline transportation and storage, emission credits and other related products through over-the-counter and futures markets across North America. PG&E NEG's energy marketing and trading team manages the supply of fuel for, and the sale of electric output from, its owned and controlled generating facilities and other trading positions. PG&E NEG also evaluates and implements structured transactions, including management of third of third party energy assets, tolling arrangements, management of the requirements of aggregated customer load through full requirement contracts, restructured independent power project contracts and purchase and sale of transportation, storage and transmission rights through auctions, and over-the-counter markets.

PG&E NEG uses financial instruments such as futures, options, swaps, exchange for physical, contracts for differences, and other derivatives to provide flexible pricing to customers and suppliers and manage PG&E NEG's purchase and sale commitments, including those related to owned and controlled generating facilities, gas pipelines and storage facilities. PG&E NEG also uses derivative financial instruments to reduce exposure relative to the volatility of market prices and to hedge weather, interest rate and currency volatility.

Electricity. PG&E NEG aggregates electricity and related products from its owned and controlled generating facilities and from other generators and marketers. PG&E NEG then packages and sells such electricity and related products to electric utilities, municipalities, cooperatives, large industrial companies, aggregators, and other marketing and retail entities. PG&E NEG also buys, sells and transports power to and from third parties under a variety of short-term contracts. PG&E NEG manages most of its power positions from its owned and controlled generating facilities as an integrated power portfolio.

Natural Gas. PG&E NEG purchases natural gas from a variety of suppliers under daily, monthly, seasonal, and long-term contracts with pricing, delivery and volume schedules to accommodate the requirements of its owned and controlled generating facilities and various transactions. PG&E NEG buys, sells, and arranges transportation and storage logistics to and from third parties under a variety of agreements. PG&E NEG's natural gas marketing activities include contracting to buy natural gas from suppliers at various points of receipt,

arranging transportation, negotiating the sale of natural gas and matching natural gas receipt and delivery points to the customer based on geographic logistics and delivery costs. PG&E NEG arranges for transportation of natural gas on interstate and intrastate pipelines through a variety of means, including short-term and long-term firm and interruptible agreements. PG&E NEG also enters into various short-term and long-term firm and interruptible agreements for natural gas storage in order to offer peak delivery services to satisfy winter heating and summer electric generating demands. These services are designed to provide an additional level of performance security, flexibility, and risk mitigation to PG&E NEG's generating facilities and customers.

Coal, Oil and Emissions. PG&E NEG buys, secures transportation for, and manages the sulfur content of, the coal and oil requirements of its owned and controlled generating facilities. PG&E NEG also purchases and sells coal, oil, and emissions credits from and to third parties.

Fuel Supply, Fuel Transportation, and Electric Transmission Management. PG&E NEG enters into contracts for fuel supply, fuel transportation, and electric transmission primarily to meet the needs of its owned and controlled generating facilities and to capitalize on other trading opportunities. PG&E NEG believes that access to long-term fuel supply, fuel transportation, and electric transmission allows it to better respond to market cycles and one-time events. As such, PG&E NEG seeks to maintain a variety of relationships with large producers and transporters with whom it enters into select long-term commitments.

Load Management or Full Requirements Arrangements. Deregulation of the energy industry has provided many consumers with the ability to seek and receive customized energy services. Consumers are particularly interested in purchasing volumes of fuel and electricity that closely match their specific needs. In order to satisfy consumer demand, an increasing number of companies aggregate blocks of customers, buy power at wholesale prices, and deliver it to end-user consumers. These aggregation services are especially critical because electricity is a commodity that generally cannot be stored, and therefore the electricity must be generated at the same time as it is needed for consumption. As part of PG&E NEG's integrated energy and marketing business, PG&E NEG enters into contracts to supply natural gas and electricity, known as load management or full requirements supply, to these load aggregator companies in the exact amount and quality purchased by their end-user customers.

PG&E NEG's largest load management contracts are the wholesale standard offer service agreements with affiliates of NEPCo, from which PG&E NEG purchased 4,800 MW of owned and controlled generating capacity in 1998. Under the wholesale standard offer service agreements, PG&E NEG supplies a fixed percentage of the full requirements of the retail customers of NEPCo's affiliates who receive standard offer service in Massachusetts and Rhode Island. These retail customers may select alternative suppliers at any time. PG&E NEG receives a fixed floor price for the electricity provided under the wholesale standard offer service agreements. The base price increases periodically by specified amounts and also increases if the prices of natural gas and fuel oil exceed a specified threshold. PG&E NEG's sales volumes and revenues under the wholesale standard offer service agreements totaled 17 million MW hours and $587 million in 1999, 13 million MW hours and $563 million in 2000, and 12 million MW hours and $629 million in 2001, respectively. The wholesale standard offer service agreement for Massachusetts terminates on December 31, 2004, and the wholesale standard offer service agreement for Rhode Island terminates on December 31, 2009 **.**

ENVIRONMENTAL MATTERS

Environmental Matters

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

PG&E Corporation, the Utility, and various PG&E NEG affiliates (including USGen New England, Inc. (USGenNE)) are subject to a number of federal, state, and local laws and regulations designed to protect human health and the environment by imposing stringent controls with regard to planning and construction activities, land use, air and water pollution, and treatment, storage, and disposal of hazardous or toxic materials. These laws and regulations affect future planning and existing operations, including environmental protection and remediation activities. The Utility has undertaken compliance efforts with specific emphasis on its purchase, use, and disposal of hazardous materials, the cleanup or mitigation of historic waste spill and disposal activities, and the upgrading or replacement of the Utility's bulk waste handling and storage facilities. The costs of compliance with environmental laws and regulations generally have been recovered in rates.

Although the Utility has sold most of its fossil-fueled power plants and its geothermal generation facilities in connection with electric industry restructuring, the Utility has retained liability for certain required environmental remediation of pre-closing soil or groundwater contamination for fossil-fueled and geothermal generation facilities that have been sold. See "Utility Operations—Electric Utility Operations—California Electric Industry Restructuring—Generation Divestiture and Market Valuation" above.

Environmental Protection Measures

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

Air Quality

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

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

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

Region. Implementation of Phase 1 was the installation of Reasonably Available Control Technology, or RACT, no later than May 31, 1995. This was successfully completed. Phase 2 commenced in 1999 and will continue through 2002. Phase 3 will begin in 2003. Among other things, the rules implementing Phases 2 and 3:

- establish NOx budgets, or emissions caps during the ozone season of May through September;
- establish methodology to allocate the allowances to affected sources within the budget; and
- require an affected source to account for ozone season NOx emissions through the surrender of NOx allowances.

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

The U.S. Environmental Protection Agency (EPA) also has initiated several regulatory efforts that are intended to impose limitations on major NOx sources located in the eastern United States and the Midwest in order to reduce the formation and regional transport of ozone. Such regulatory efforts include the EPA's "Section 126 Rule" and the "NOx SIP Rule call," which together would establish a federal NOx emissions cap-and-trade program that would apply to some existing utilities and large industrial sources located in midwestern and eastern states whose emissions the EPA has determined contribute to air quality problems in "downwind" states (generally in the northeast corner of the United States). Aspects of both rules remain the subject of litigation.

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

The Utility's Gas Accord authorizes $42 million to be included in rates through 2002 for gas NOx retrofit projects related to natural gas compressor stations on the Utility's Line 300, which delivers gas from the Southwest. Other air districts are considering NOx rules that would apply to the Utility's other natural gas compressor stations in California. Eventually the rules are likely to require NOx reductions of up to 80% at many of these natural gas compressor stations. The Utility currently estimates that the total cost of complying with these various NOx rules will be up to $30 million from 2002 through 2004. The Utility is planning to replace some compressor units because proven NOx retrofit technology is not available for these units. Substantially all of these costs will be capital costs.

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

The EPA also has been conducting a nationwide enforcement investigation regarding the historical compliance of coal-fueled electric generating stations with various permitting requirements of the Federal Clean Air Act. Specifically, the EPA and the U.S. Department of Justice have recently initiated enforcement actions against a number of electric utilities, several of which have entered into substantial settlements for alleged Federal Clean Air Act violations related to modifications (sometimes more than 20 years ago) of existing coal-fired generating

facilities. In May 2000, USGenNE received an Information Request from the EPA, pursuant to Section 114 of the Federal Clean Air Act. The Information Request asked USGenNE to provide certain information, relative to the compliance of USGenNE's Brayton Point and Salem Harbor Generating Stations with the Federal Clean Air Act. No enforcement action has been brought by the EPA to date. USGenNE has had very preliminary discussions with the EPA to explore a potential settlement of this matter. It is not possible to predict whether any such settlement will occur or, in the absence of a settlement, the likelihood of whether the EPA will bring an enforcement action.

In addition to the EPA, states may impose more stringent air emissions requirements. On May 11, 2001, the Massachusetts Department of Environmental Protection (DEP) issued regulations imposing new restrictions on emissions of NOx and SO2, mercury and CO2 from existing coal and oil-fired power plants. These restrictions will impose more stringent annual and monthly limits on NOx and SO2 emissions than currently exist and will take effect in stages, beginning in October 2004 if no permits are needed for the changes necessary to comply, and beginning in 2006 if such permits are needed. The DEP has informed USGenNE that, based upon its current understanding of the facilities' plans for compliance with the new regulations, it believes that permits will be needed and that the initial compliance date will therefore be 2006. However, the need for permits triggers an obligation to meet Best Available Control Technology, or BACT, requirements. USGenNE does not believe that compliance with BACT at the facilities requires implementation of controls beyond those otherwise necessary to meet the emissions standards in the new regulations. Mercury emissions are capped as a first step and must be reduced by October 2006 pursuant to standards to be developed. CO2 emissions are regulated for the first time and must be reduced from recent historical levels. USGenNE believes that compliance with the CO2 caps can be achieved through implementation of a number of strategies, including sequestrations and offsite reductions. Various testing and record keeping requirements are also imposed. USGenNE filed its plan to comply with the new regulations with the DEP at the end of 2001. The new Massachusetts regulations affect primarily USGenNE's Brayton Point and Salem Harbor generating facilities, representing approximately 2,300 MW. Through 2006, it may be necessary to spend approximately $266 million to comply with these regulations. In addition, with respect to approximately 600 MW (or about 12%) of USGenNE's New England capacity, USGenNE may need to implement fuel conversion, limit operations, or install additional environmental controls. These new regulations require that USGenNE achieve specified emission levels earlier than the dates included in a previous Massachusetts initiative to which USGenNE had agreed.

Water Quality

The Federal Clean Water Act generally prohibits the discharge of any pollutants, including heat, into any body of surface water, except in compliance with a discharge permit issued by a state environmental regulatory agency and/or the EPA. All of PG&E NEG's facilities that are required to have such permits either have them or have timely applied for extensions of expired permits and are operating in substantial compliance with the prior permit. At this time, three of the fossil-fuel plants owned and operated by USGenNE (Manchester Street, Brayton Point and Salem Harbor stations) are operating pursuant to permits that have expired. For the facilities whose water discharge permits (National Pollutant Discharge Elimination System (NPDES)) have expired, permit renewal applications are pending, and USGenNE anticipates that all three facilities will be able to continue to operate in substantial compliance with prior permits until new permits are issued. It is possible that the new permits may contain more stringent limitations than the prior permits. It is estimated that USGenNE's cost to comply with new permit conditions could be approximately $67 million through 2005.

At Brayton Point, unlike the Manchester Street and Salem Harbor generating facilities, PG&E NEG has agreed to meet certain restrictions that were not in the expired NPDES permit. In October 1996, the EPA announced its intention to seek changes in Brayton Point's NPDES permit based on a report prepared by the Rhode Island Department of Environmental Management, which alleged a connection between declining fish populations in Mt. Hope Bay and thermal discharges from the Brayton Point once-through cooling system. In April 1997, the former owner of Brayton Point entered into a Memorandum of Agreement, or MOA, with various governmental entities regarding the operation of the Brayton Point station cooling water systems pending

issuance of a renewed NPDES permit. This MOA, which is binding on PG&E NEG, limits on a seasonal basis the total quantity of heated water that may be discharged to Mt. Hope Bay by the plant. While the MOA is expected to remain in effect until a new NPDES permit is issued, it does not in any way preclude the imposition of more stringent discharge limitations for thermal and other pollutants in a new NPDES permit and it is possible that such limitations will in fact be imposed. If such limitations are imposed, compliance with such additional limitations could have a material adverse effect on PG&E NEG's financial condition, cash flows and results of operations. In addition, the EPA, as well as local environmental groups, have previously expressed concern that the metal vanadium is not addressed at Brayton Point or Salem Harbor under the terms of the old NPDES permits and it may raise this issue in upcoming NPDES permit negotiations. Based upon the lack of an identified control technology, PG&E NEG believes it is unlikely that the EPA will require that vanadium be addressed pursuant to a NPDES permit. However, if the EPA does insist on including vanadium in the NPDES permit, PG&E NEG may have to spend a significant amount to comply with such a provision.

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

The Diablo Canyon Power Plant employs a "once through" cooling water system which is regulated under a NPDES permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, recreation, commercial/sport fishing, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, Diablo Canyon's discharge was not protective of beneficial uses. In October 2000, the Central Coast Board and the Utility reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology meets the BTA requirements. As part of the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $4.5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment prior to final approval by the Central Coast Board and, once signed by the parties, will be incorporated in a consent decree to be entered in California Superior Court. A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with Diablo Canyon's operation of its cooling water system.

For a description of another environmental regulatory matter affecting the Utility, see "Item 3—Legal Proceedings—Moss Landing Power Plant" below.

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

Hazardous Waste Compliance and Remediation

The Utility's and PG&E NEG's facilities are subject to the requirements promulgated by the EPA under the Resource Conservation and Recovery Act (RCRA) and the Comprehensive Environmental Response,

Compensation and Liability Act (CERCLA), along with other state hazardous waste laws and other environmental requirements. The Utility and PG&E NEG assess, on an ongoing basis, measures that may need to be taken to comply with federal, state and local laws and regulations related to hazardous materials and hazardous waste compliance and remediation activities. The Utility has a comprehensive program to comply with hazardous waste storage, handling, and disposal requirements promulgated by the EPA under the RCRA and the CERCLA, along with other state hazardous waste laws and other environmental requirements.

One part of the Utility's program is aimed at assessing whether and to what extent remedial action may be necessary to mitigate potential hazards posed by certain disposal sites and retired manufactured gas plant sites. During their operation, manufactured gas plants produced lampblack and tar residues, byproducts of a process that Pacific Gas and Electric Company, its predecessor companies, and other utilities used as early as the 1850s to manufacture gas from coal and oil. As natural gas became widely available (beginning about 1930), the Utility's manufactured gas plants were removed from service. The residues that may remain at some sites contain chemical compounds that now are classified as hazardous. The Utility has identified and reported to federal and California environmental agencies 96 manufactured gas plant sites that operated in the Utility's service territory. The Utility owns all or a portion of 29 of these manufactured gas plant sites. The Utility has a program, in cooperation with environmental agencies, to evaluate and take appropriate action to mitigate any potential health or environmental hazards at sites that the Utility owns. It is estimated that the Utility's program may result in expenditures of approximately $5 million in 2002. The full long-term costs of the program cannot be determined accurately until a closer study of each site has been completed. It is expected that expenses will increase as remedial actions related to these sites are approved by regulatory agencies or if the Utility is found to be responsible for cleanup at sites it currently does not own.

In addition to the manufactured gas plant sites, the Utility may be required to take remedial action at certain other disposal sites if they are determined to present a significant threat to human health and the environment because of an actual or potential release of hazardous substances. With respect to the Casmalia site near Santa Maria, California, the Utility and several other generators of waste sent to the site have entered into a court-approved agreement with the EPA that requires these generators to perform certain site investigation and mitigation measures, and provides a release from liability for certain other site cleanup obligations. Recently, the EPA asserted that the Utility sent more waste to the site than was believed previously. The Utility is evaluating the significance of this information, which may affect the amount the Utility ultimately has to pay for this site. Although the Utility has not been formally designated a potentially responsible party (PRP) with respect to the Geothermal Incorporated site in Lake County, California, the Central Valley Regional Water Quality Control Board and the California Attorney General's office have directed the Utility and other parties to initiate measures with respect to the study and remediation of that site.

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

The cost of hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. It is reasonably possible that a change in the estimate may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. At December 31, 2001, the Utility expected to spend $295 million for hazardous waste remediation costs at identified sites, including divested fossil-fueled power plants, where such costs are probable and quantifiable. (Although the Utility has sold most of its fossil-fueled power plants, the Utility has retained pre-closing environmental liability with respect to these plants.) Environmental remediation at identified sites may be as much as $446 million if, among other things, other PRPs are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated at sites for which the Utility is responsible. The Utility estimated the upper limit of the range of costs using assumptions least favorable to the Utility based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for cleanup costs at additional sites or identifiable possible outcomes change.

On June 26, 2001, the Bankruptcy Court authorized the Utility to spend (1) up to $22 million in each calendar year in which the Chapter 11 case is pending to continue its hazardous substance remediation programs and procedures, and (2) any additional amounts necessary in emergency situations involving post-petition releases or threatened releases of hazardous substances, if such excess expenditures are necessary in the Utility's reasonable business judgment to prevent imminent harm to public health and safety or the environment (provided that the Utility seeks the Bankruptcy Court's approval of such emergency expenditures at the earliest practicable time).

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

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

During April 2000, an environmental group served various affiliates of PG&E NEG, including USGenNE, with a notice of intent to file a citizen's suit under RCRA. In September 2000, PG&E NEG signed a series of agreements with the Massachusetts Department of Environmental Protection and the environmental group to resolve these matters that require USGenNE to alter its existing wastewater treatment facilities at its Brayton Point and Salem Harbor generating facilities. USGenNE began the activities during 2000 and expects to complete them in 2002. USGenNE has incurred expenditures related to these agreements of approximately $2.4 million in 2001 and $5.8 million in 2000. In addition to the costs incurred in 2000 and 2001, at December 31, 2001, USGenNE maintains a reserve in the amount of $10 million relating to its estimate of the remaining environmental expenditures to fulfill its obligations under these agreements.

Potential Recovery of Hazardous Waste Compliance and Remediation Costs

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

For each divested generation facility for which the Utility retained environmental remediation liabilities, the plant's decommissioning cost estimate was adjusted by the Utility's estimated forecast of environmental remediation costs. (The buyers assumed the non-environmental decommissioning liability for these plants.) The CPUC ordered that excess recoveries of environmental and non-environmental decommissioning accruals related to the divested plants be used to offset other transition costs. As of December 31, 2001, the Utility had recovered from ratepayers approximately $139 million for environmental decommissioning accrual related to the divested plants. This amount will earn interest at 3% per year that will be used to meet the future environmental remediation costs for the divested plants. The net decommissioning accruals recovered from ratepayers attributable to the non-environmental liability for the divested plants was approximately $50 million. Because the Utility no longer has this non-environmental decommissioning liability, it has used this excess recovery amount to reduce other transition costs.

The $295 million accrued environmental remediation liability at December 31, 2001, mentioned above, includes (1) $139 million related to the pre-closing remediation liability, discounted to present value at 7%, associated with divested generation facilities (see further discussion in the "Generation Divestiture" section of Note 2 of the Notes to the Consolidated Financial Statements of the 2001 Annual Report to Shareholders), and (2) $156 million related to remediation costs for those generation facilities that the Utility still owns. Of the $295 million environmental remediation liability, the Utility has recovered $193 million through rates, and expects to recover another $91 million in future rates. The Utility is seeking recovery of the remainder of its costs from insurance carriers and from other third parties as appropriate.

In 1992, Pacific Gas and Electric Company filed a complaint in San Francisco County Superior Court against more than 100 of its domestic and foreign insurers, seeking damages and declaratory relief for remediation and other costs associated with hazardous waste mitigation. The Utility previously had notified its insurance carriers that it seeks coverage under its comprehensive general liability policies to recover costs incurred at certain specified sites. In general, the Utility's carriers neither admitted nor denied coverage, but requested additional information from the Utility. Although the Utility has received some amounts in settlements with certain of its insurers (approximately $139 million through December 31, 2001), the ultimate amount of recovery from insurance coverage, either in the aggregate or with respect to a particular site, cannot be quantified at this time. Insurance recoveries are subject to the HWRC mechanism discussed above.

Compressor Station Litigation

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

Electric and Magnetic Fields

In January 1991, the CPUC opened an investigation into potential interim policy actions to address increasing public concern, especially with respect to schools, regarding potential health risks that may be associated with electric and magnetic fields (EMF) 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 EMF, 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 EMF from new and upgraded utility facilities. California energy utilities are required to fund a $1.5 million EMF education program and a $5.6 million EMF research program managed by the California Department of Health Services. It is expected that the CPUC and the California Department of Health Services will complete its EMF research program and submit to the CPUC in June 2002.

As part of its effort to educate the public about EMF, Pacific Gas and Electric Company provides interested customers with information regarding the EMF exposure issue. The Utility also provides a free field measurement service to inform customers about EMF levels at different locations in and around their residences or commercial buildings.

The Utility currently is not involved in third-party litigation concerning EMF. In August 1996, the California Supreme Court held that homeowners are barred from suing utilities for alleged property value losses caused by fear of EMF 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 EMF are similarly barred. The Utility was a defendant in civil litigation in which plaintiffs alleged personal injuries resulting from exposure to EMF. 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 EMF 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.

If the scientific community reaches a consensus that EMF presents a health hazard and further determines that the impact of utility-related EMF exposures can be isolated from other exposures, the Utility may be required to take mitigation measures at its facilities. The costs of such mitigation measures cannot be estimated with any certainty at this time. However, such costs could be significant, depending on the particular mitigation measures undertaken, especially if relocation of existing power lines ultimately is required.

Low Emission Vehicle Programs

In December 1995, the CPUC issued its decision in the Low Emission Vehicle (LEV) proceeding, which approved approximately $42 million in funding for the Utility's LEV program for the six-year period beginning in 1996. The LEV program expired on December 20, 2001. On January 23, 2002, the CPUC approved bridge funding of $8 million for the LEV program. The bridge funding will end either at the end of 2002 or when the CPUC approves a renewal of the LEV program. The Utility must submit an application by March 25, 2002, justifying the renewal of the LEV program. Each of the California investor-owned utilities has requested the CPUC to continue their respective LEV programs.

ITEM 2. Properties.

Information concerning Pacific Gas and Electric Company's electric generation units, electric and gas transmission facilities, and electric and gas distribution facilities is included in response to Item 1. All of the Utility's real properties and substantially all of the Utility's personal properties are subject to the lien of an indenture that provides security to the holders of the Utility's First and Refunding Mortgage Bonds.

Information concerning properties and facilities owned by PG&E National Energy Group, Inc. and other PG&E Corporation subsidiaries is included in the discussion under the heading of this report entitled "PG&E National Energy Group, Inc."

ITEM 3. Legal Proceedings.

See Item 1, Business, for other proceedings pending before governmental and administrative bodies. In addition to the following legal proceedings, PG&E Corporation and Pacific Gas and Electric Company are subject to routine litigation incidental to their business.

Pacific Gas and Electric Company Bankruptcy

On April 6, 2001, Pacific Gas and Electric Company filed a voluntary petition for relief under the provisions of Chapter 11 of the U.S. Bankruptcy Code (Bankruptcy Code) in the U.S. Bankruptcy Court for the Northern District of California (Bankruptcy Court). Pursuant to Chapter 11 of the U.S. Bankruptcy Code, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. For more information about the Utility's financial condition and the factors leading up to the filing for bankruptcy protection, see "Management's Discussion and Analysis" and Notes 2 and 3 of the 2001 Annual Report to Shareholders, which portions are incorporated herein by reference and filed as Exhibit 13 to this report.

Bankruptcy law imposes an automatic stay to prevent parties from making certain claims or taking certain actions that would interfere with the estate or property of a Chapter 11 debtor. In general, the Utility may not pay pre-petition debts without the Bankruptcy Court's permission. Under the Bankruptcy Code, the Utility has the right to reject or assume executory contracts (contracts that require material future performance). Since the filing, the Bankruptcy Court has approved various requests by the Utility to permit the Utility to carry on its normal business operations (including payment of employee wages and benefits, refunds of certain customer deposits, use of certain bank accounts and cash collateral, the assumption of various hydroelectric contracts with water agencies and irrigation districts, and the continuation of environmental remediation and capital expenditure programs) and to fulfill certain post-petition obligations to suppliers and creditors.

Through September 5, 2001, the last day for non-governmental creditors to file proofs of claim, non-governmental claims had been submitted for an approximate aggregate amount of $42.1 billion. This amount includes claims filed by generators, which the Utility believes have been overstated and claims by financial institutions, which the Utility believes contains significant duplication. (Further, as discussed below, the Bankruptcy Court has disallowed approximately $9 billion of claims filed by non-governmental entities.) In addition, through October 3, 2001, the last day for governmental entities to file proofs of claim, claims had been submitted by various governmental agencies for an approximate aggregate amount of $1.9 billion. These include, but are not limited to, contingent environmental claims, claims for federal, state and local taxes, and claims submitted by the DWR for approximately $430 million for certain energy purchases made on behalf of the Utility's retail customers. In addition, on or about December 26, 2001, the DWR filed an administrative claim arising from the sale of energy for approximately $35 million for August 1, 2001, through August 31, 2001.

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

On April 9, 2001, the Utility filed a complaint in the Bankruptcy Court against the CPUC and its Commissioners requesting that the court declare that any attempt by the CPUC to implement or enforce the regulatory accounting changes approved by the CPUC on March 27, 2001, would violate the automatic stay imposed by bankruptcy law, and asking the court to enjoin implementation or enforcement of such accounting changes. On June 1, 2001, the Bankruptcy Court issued a decision denying the Utility's request for an injunction and granted the CPUC's motion to dismiss the complaint. Although the Court held that the Eleventh Amendment to the U.S. Constitution did not bar the Utility's suit against the individual Commissioners, the Court concluded that the Utility was not entitled to a stay or an injunction to prevent implementation and enforcement of the regulatory accounting order. First, the Court held that, assuming the Bankruptcy Code provision imposing an automatic stay on pre-petition proceedings might ordinarily apply (an issue that the Court expressly declined to decide), the Court determined that the Commissioners were acting pursuant to their police and regulatory power when issuing the order. Accordingly, the Court found that the CPUC's March 27, 2001, order was exempt from the automatic stay provision pursuant to a statutory exemption for the commencement or continuation of an action or proceeding by a governmental unit to enforce such governmental unit's police and regulatory power. Second, the Court held that the Utility had not shown any actual or threatened violation of federal law sufficient to warrant injunctive relief, nor did the balance of equities favor an injunction. The Utility has initiated an appeal of the Bankruptcy Court's decision to the U.S. District Court for the Northern District of California, and the CPUC and its Commissioners have initiated a cross-appeal, both of which are pending. On January 2, 2002, the CPUC denied the Utility's application for rehearing of the CPUC's March 27, 2001, accounting decision.

On May 2, 2001, the Utility also filed a complaint for injunctive and declaratory relief in the Bankruptcy Court asking the court to prohibit the ISO from charging the Utility for the ISO's wholesale power purchases made in violation of bankruptcy law, the ISO's tariff, and the FERC's February 14 and April 6, 2001 orders. In its complaint, the Utility also seeks to have the court declare that any action by the ISO to purchase wholesale power for or on behalf of the Utility at costs the Utility is not permitted to fully recover through the generation-related cost component of retail rates, to compel the Utility to accept and pay for such purchases, or to accrue post-petition debt for such purchases (i.e., to accrue debts after April 6, 2001, when the Utility filed its petition under Chapter 11 of the federal Bankruptcy Code), is automatically stayed by bankruptcy law. In addition, the complaint seeks a permanent injunction prohibiting the ISO from taking such actions. On June 18, 2001 the Bankruptcy Court granted a motion by Reliant Energy, Inc. and Reliant Energy Services, Inc. (collectively, Reliant) to intervene in the Utility's action against the ISO. Reliant has intervened in the action to seek a permanent injunction barring the ISO from procuring power to meet the Utility's net short position in violation of its tariff and applicable FERC orders. If the Bankruptcy Court declines to issue such an injunction, Reliant has asked the Court in the alternative to declare that the Utility is liable to Reliant for power procured by the ISO from Reliant and delivered to the Utility's service area. On June 26, 2001, the Bankruptcy Court issued a preliminary injunction prohibiting the ISO from violating the FERC orders discussed above and from filing administrative claims against the Utility in the bankruptcy for ISO charges for wholesale power purchases and other services in the ISO market. Thereafter, the parties commenced discovery. On November 7, 2001, FERC entered an order requiring payment by the DWR of outstanding invoices and directing the ISO to bill the DWR directly for its power purchases. The DWR subsequently filed for rehearing of FERC's November 7, 2001 order, which request remains pending.

On September 20, 2001, the Utility and PG&E Corporation jointly filed with the Bankruptcy Court a proposed plan of reorganization (Plan) and disclosure statement under Chapter 11 of the U.S. Bankruptcy Code. On October 2, 2001, the Utility filed with the Bankruptcy Court the Support Agreement between the Utility and the Official Unsecured Creditors' Committee under which the Committee has agreed to support the Plan under the conditions specified in the agreement. Both the Plan and the disclosure statement were amended on December 19, 2001, and again on February 4, 2002, in an effort to resolve objections that had been filed by various parties.

The Plan contemplates that the Utility will disaggregate and restructure its business by transferring certain assets and liabilities of its traditional business lines to newly created limited liability companies. The Plan

proposes that the majority of the assets and liabilities associated with the Utility's electric transmission business will be transferred to ETrans LLC (ETrans), the majority of the assets and liabilities associated with the Utility's gas transmission business will be transferred to GTrans LLC (GTrans), and the majority of the assets and liabilities associated with the Utility's generation business will be transferred to Electric Generation LLC (Gen) and its subsidiaries. The Utility also has created subsidiaries or affiliates to hold other assets and may create additional entities as deemed necessary. In addition, the Utility has created Newco Energy Corporation (Newco) to hold the membership interests of each of ETrans, GTrans, and Gen. The Utility is the sole shareholder of Newco. The Plan proposes that certain other assets of the Utility deemed not essential to operations will be sold to third parties or transferred to one or more special purpose entities wholly owned by Newco under the Plan. The Plan also proposes that the Utility will declare and, after the assets are transferred to the newly formed entities, pay a dividend of all of the outstanding common stock of Newco to PG&E Corporation, and each of ETrans, Gtrans, and Gen will continue to be an indirect wholly owned subsidiary of PG&E Corporation (the foregoing transactions are referred to herein collectively as the "Internal Restructurings"). The reorganized Utility would retain the name "Pacific Gas and Electric Company." Finally, the Plan contemplates that, on or as soon as practicable after the date on which the Plan becomes effective (Effective Date), PG&E Corporation will distribute the shares of the reorganized Utility's common stock it holds to the holders of PG&E Corporation common stock on a pro rata basis. On November 30, 2001, the Utility and PG&E Corporation on behalf of its subsidiaries ETrans, GTrans, and Gen, filed various applications with the FERC seeking approval to implement the proposed Internal Restructurings. For additional information about the proposed Plan and the regulatory approvals required to implement the Plan, see Note 2 of the Notes to Consolidated Financial Statements appearing in the 2001 Annual Report to Shareholders.

On January 16, 2002, the Bankruptcy Court issued an order granting the Utility's motion to extend the period during which only the Utility has the right to submit a proposed plan of reorganization from February 4, 2002, when the period would otherwise expire, to June 30, 2002. However, with respect to the CPUC, the Bankruptcy Court's order allowed the CPUC to submit a term sheet regarding an alternative proposed plan of reorganization by February 13, 2002. The Bankruptcy Court indicated that the CPUC's term sheet for its proposed plan must demonstrate that the proposed plan would be clearly credible and capable of being confirmed. The Bankruptcy Court stated that its order was merely allowing the CPUC an opportunity to seek to demonstrate to the Bankruptcy Court that the CPUC should be permitted to file an alternative plan. On February 13, 2002, the CPUC submitted its term sheet describing the principal terms of its alternative plan. Although the alternative plan is similar to the CPUC's settlement agreement reached with Southern California Edison in 2001, it contains significant differences. For more information about the CPUC's alternative plan see Note 2 of the Notes to Consolidated Financial Statements appearing in the 2001 Annual Report to Shareholders. On February 27, 2002, the Bankruptcy Court decided that it would permit the CPUC to file its alterative plan of reorganization by April 15, 2002. The Bankruptcy Court also has directed the Utility, the CPUC, and representatives of the State of California to meet with a neutral third party, such as a mediator, to seek to resolve any disputed issues relating to the Utility's plan of reorganization.

On January 25, 2002, the Bankruptcy Court held a hearing to consider arguments as to whether the Bankruptcy Court has the power to preempt various California state and local laws as requested in the Plan, and whether such preemption would violate the sovereign immunity of the State of California and its agencies, including the CPUC. On February 7, 2002, the Bankruptcy Court issued an order concluding that bankruptcy law does not permit express preemption, but it does permit implied preemption. The Bankruptcy Court rejected the proponents' argument that Section 1123(a)(5) of the Bankruptcy Code expressly authorized the Bankruptcy Court to preempt any state law to confirm and effectuate a plan of reorganization. Instead, the Bankruptcy Court interpreted Section 1123(a)(5) to permit preemption of a state law where it had been shown that enforcing the state law at issue would be an obstacle to the accomplishment and execution of the full purposes of the bankruptcy laws. The Bankruptcy Court stated that whether a restructuring; i.e., the disaggregation of the Utility's businesses as proposed in the Plan, is necessary for a feasible reorganization is an issue to be determined at the confirmation hearing.

The proponents also intend to file a request with the Bankruptcy Court seeking interlocutory certification of the February 7, 2002 decision so that the proponents can appeal the decision.

On February 12, 2002, PG&E Corporation, the Utility, and a group of the Utility's senior unsecured debtholders, entered into a Settlement and Support Agreement for the settlement of certain disputes relating to the treatment afforded Class 5 General Unsecured Claims under the amended Plan. Under the settlement, the debtholders agreed to withdraw their objections to the disclosure statement and Plan, to support confirmation of the Plan, and to vote their claims in favor of the Plan. PG&E Corporation and the Utility have agreed to pay the debtholders pre- and post-petition interest on the principal amount of such claims at certain rates of interest which differ from the rates originally proposed in the Plan. In addition, the interest rate will increase if the Effective Date has not occurred by certain dates. Other than with respect to the debtholders' agreement to withdraw their objections to the disclosure statement and Plan, the settlement will become effective only (i) if the Bankruptcy Court approves the disclosure statement, (ii) the Bankruptcy Court approves the Settlement and Support Agreement, and (iii) a sufficient number of debtholders have entered into the Settlement and Support Agreement or similar agreements. For more information, see Note 2 of the 2001 Annual Report to Shareholders.

Pursuant to the Bankruptcy Court's February 7, 2002 decision, the Plan and disclosure statement will be amended to (1) eliminate express preemption provisions so they can proceed to a confirmation hearing where PG&E Corporation and the Utility intend to show that implied preemption of specified statutes is available to confirm the Plan, and (2) state with specificity the facts demonstrating that the State and the CPUC have waived their sovereign immunity, and, in the event the Bankruptcy Court finds that such immunity has been waived, to provide for declaratory and injunctive relief against the State and the CPUC. The amended Plan and disclosure statement will be filed by March 7, 2002. Objections to the amended Plan and disclosure statement must be filed with the Bankruptcy Court by March 19, 2002. The Bankruptcy Court has scheduled a hearing for March 26, 2002 to consider the adequacy of the amended disclosure statement and to resolve objections.

Pacific Gas and Electric Company vs. California Public Utilities Commissioners

On November 8, 2000, Pacific Gas and Electric Company filed a lawsuit in the U.S. District Court for the Northern District of California against the CPUC Commissioners, asking the court to declare that the federally approved wholesale power costs that the Utility has incurred to serve its customers are recoverable in retail rates. As of December 31, 2000, the uncollected wholesale power purchase costs recorded in the Utility's TRA were $6.6 billion. On January 29, 2001, the Utility's lawsuit was transferred to the U.S. District Court for the Central District of California where a similar lawsuit filed by Southern California Edison is pending.

On May 2, 2001, the District Court dismissed the Utility's amended complaint, without prejudice to refiling at a later date, on the ground that the lawsuit was premature since two CPUC decisions had not become final under California law. The court rejected all of the CPUC's other arguments for dismissal of the Utility's complaint.

On August 6, 2001, the Utility refiled its complaint in the U.S. District Court for the Northern District of California, based on the Utility's belief that the CPUC decisions referenced in the Court's May 2, 2001 order had become final under California law. The CPUC and TURN have filed motions to dismiss the complaint. On November 26, 2001, the case was transferred to District Court Judge Walker in the Northern District of California and consolidated as a related case with the Utility's appeal of the Bankruptcy Court's denial of the Utility's request for injunctive and declaratory relief against the retroactive accounting order adopted by the CPUC in March 2001. A case management conference in both actions is scheduled for March 7, 2002.

The Utility's complaint states that the wholesale power costs which the Utility has prudently incurred are paid pursuant to filed rates which 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. The Utility's complaint also alleges that to the extent that the Utility is denied recovery of these mandated wholesale power costs by order of

the CPUC, such action constitutes an unlawful taking and confiscation of the Utility's property. The Utility argues that the CPUC's decisions violate federal preemption law and the filed rate doctrine, which requires the CPUC to allow the Utility to recover in full its reasonable procurement costs incurred under lawful rates and tariffs approved by the FERC, a federal governmental agency. The complaint also pleads claims under the Commerce Clause, Due Process Clause, and Equal Protection Clause of the U.S. Constitution.

In connection with the proposed Plan, before the distribution of the outstanding common stock of Newco to PG&E Corporation, the Utility will assign to Newco or a subsidiary of Newco the rights to an amount equal to 95% of the net after-tax proceeds from any successful resolution of this case and resulting CPUC rate order requiring collection of wholesale costs in retail rates. The reorganized Utility will retain the rights to 5 percent of such proceeds.

Federal Securities Lawsuit

On April 16, 2001, a complaint was filed against PG&E Corporation and the Utility in the U.S. District Court for the Central District of California entitled *Jack Gillam; DOES 1 TO 5, Inclusive, and All Persons similarly situated vs. PG&E Corporation, Pacific Gas and Electric Company; and DOES 6 to 10, Inclusive.* The complaint was filed after the Utility filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. The Utility informed plaintiff that the action is stayed by the automatic stay provisions of the Bankruptcy Code and on or about April 23, 2001, plaintiff filed a notice of voluntary dismissal without prejudice with respect to the Utility. By order entered on or about May 31, 2001, the case was transferred to the U.S. District Court for the Northern District of California.

On August 9, 2001, plaintiff filed a first amended complaint entitled *Jack Gillam, et al. vs. PG&E Corporation, Robert D. Glynn, Jr., and Peter A. Darbee*, in the U.S. District Court for the Northern District of California. The first amended complaint, purportedly brought on behalf of all persons who purchased PG&E Corporation common stock or certain shares of the Utility's preferred stock between July 20, 2000, and April 9, 2001, claims that defendants caused PG&E Corporation's Condensed Consolidated Financial Statements for the second and third quarters of 2000 to be materially misleading in violation of federal securities laws by recording as a deferred cost and capitalizing as a regulatory asset the under-collections that resulted when escalating wholesale energy prices caused the Utility to pay far more to purchase electricity than it was permitted to collect from customers. The defendants filed a motion to dismiss the first amended complaint, based largely on public disclosures by PG&E Corporation, the Utility, and others regarding the under-collections, the risk that they might not be recoverable, the financial consequences of non-recovery, and other information from which analysts and investors could assess for themselves the probability of recovery. On January 14, 2002, the district court granted the defendants' motion to dismiss the plaintiffs' complaint with leave to amend the complaint. On February 4, 2002, the plaintiffs filed a second amended complaint in the U.S. District Court for the Northern District of California entitled *Jack Gillam, et al. vs. PG&E Corporation, and Robert D. Glynn, Jr* . In addition to containing many of the same allegations as were contained in the prior complaint, the complaint contains allegations similar to the allegations made in the AG's complaint against PG&E Corporation discussed below. The defendants intend to file a motion to dismiss the second amended complaint.

PG&E Corporation believes the case is without merit and intends to present a vigorous defense. PG&E Corporation believes that the ultimate outcome of this litigation will not have a material adverse effect on PG&E Corporation's financial condition or results of operations.

In re: Natural Gas Royalties Qui Tam Litigation

This litigation involves the consolidation of approximately 77 False Claims Act cases filed in various federal district courts by Jack J. Gyrnberg (called a relator in the parlance of the False Claims Act) on behalf of the United States of America against more than 330 defendants, including the Utility, and PG&E GTN. 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 (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 which are pipeline companies or their affiliates) mismeasured 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 of not less than $5,000 and not more than $10,000 against each defendant for each violation of the False Claims Act, an order requiring the defendants to discontinue certain measurement practices, and reimbursement for reasonable expenses, attorneys' fees, and costs incurred in connection with the litigation. The relator has filed a claim in the Utility's bankruptcy case for $2.48 billion, $2 billion of which is based upon the relator's calculation of penalties against the Utility.

PG&E Corporation and the Utility believe the allegations to be without merit and intend to present a vigorous defense.

PG&E Corporation and the Utility believe that the ultimate outcome of the litigation will not have a material adverse effect on their financial condition or results of operations.

Baldwin Associates

On or about September 5, 2001, Baldwin Associates, Inc. (Baldwin) filed a claim in the Bankruptcy Court in the Utility's bankruptcy case. The proof of claim form seeks relief of $5 billion and indicates that the basis of the claim is "taxes" and "other" ("economic and personal injury"). The form also indicates that the debt was incurred "[b]eginning at least [sic] September 6, 2000." The alleged claim does not provide any additional detail.

At a hearing on December 12, 2001, the bankruptcy court sustained PG&E's objection to the claim but granted Baldwin leave to amend the proof of claim by January 4, 2001. On January 7, 2001, Baldwin filed an amended claim, purportedly in the amount of $49 billion. At a hearing on January 16, 2001, the Bankruptcy Court sustained PG&E's objection and disallowed the amended claim. Among other things, the court observed that the amended proof of claim was equally incomprehensible as the original claim. Baldwin has filed a notice of appeal from the Bankruptcy Court's order.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse affect on PG&E Corporation's or the Utility's financial condition or results of operation.

Wayne Roberts

On or about September 5, 2001, Wayne Roberts filed a purported "secured" claim against the Utility in the Bankruptcy Court in the Utility's bankruptcy case. The proof of claim form stated the total amount of claim as $40.00, although, in the materials attached to the form, the claimant seeks payment to "PG&E electricity ratepayers" of not less than $4 billion, plus interest, restitution, attorneys' fees and costs. The claimant purports to bring the claim on behalf of "himself, the public, and [a] class composed of PG&E electricity ratepayers," as creditors. The allegations of the claim are similar but not identical to the allegations in two actions earlier filed in the San Francisco Superior Court, but then dismissed without prejudice, entitled *Richard D. Wilson v. Pacific Gas and Electric Company, et al.* The same lawyers who represent Wayne Roberts in his alleged bankruptcy claim, represented plaintiff Richard D. Wilson in the earlier *Wilson* cases.

Mr. Roberts asserts various legal theories including, but not limited to, purported violations of California Business and Profession Code Section 17200, California Public Utilities Code Sections 453, 817, 818, 841, and

851, 15 U.S.C. Section 79i(a)(2), various "regulations," and the doctrines of "public trust" and/or "public use," as well as constructive fraud, allegedly arising out of: (a) formation of PG&E Corporation; (b) alleged dividend payments, and repurchases of Utility common stock, made by the Utility; and (c) alleged tax payments made by the Utility to PG&E Corporation through consolidated tax preparation for the Utility and affiliate companies of PG&E Corporation.

Mr. Robert's claim contends that allegations, which relate to PG&E Corporation, will be made in an adversary proceeding of the Bankruptcy Court, or in a state court, provided the Bankruptcy Court permits Mr. Roberts to lift the automatic stay.

At a hearing on January 16, 2002, the Bankruptcy Court sustained the Utility's objections to the claim and disallowed the claim. Mr. Roberts has filed a notice of appeal from the Bankruptcy Court's order.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse affect on PG&E Corporation's or the Utility's financial condition or results of operation.

Moss Landing Power Plant

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water and organic debris from the intake, and that this procedure is not specified in the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). The purchaser notified the Central Coast Board of its findings and the Central Coast Board requested additional information from the purchaser. The Utility initiated an investigation of these activities during the time it owned the plant. The Utility notified the Central Coast Board that it had undertaken an investigation and that it would present the results to the Central Coast Board when the investigation was completed. In March 2000, the Central Coast Board requested the Utility to provide specific information regarding the "backflush" procedure used at Moss Landing. The Utility provided the requested information in April 2000. The Utility's investigation indicated that while the Utility owned Moss Landing, significant amounts of water were discharged from the cooling water intake. While the Utility's investigation did not clearly indicate that discharged waters had a temperature higher than ambient receiving water, the Utility believes that the temperature of the discharged water was higher than that of the receiving water. In December 2000, the executive officer of the Central Coast Board made a settlement proposal to the Utility under which the Utility would pay $10 million, a portion of which would be used for environmental projects and the balance of which would constitute civil penalties. Settlement negotiations are continuing.

A proof of claim has been filed in the Bankruptcy Court by the California Attorney General on behalf of the Central Coast Board seeking unspecified penalties for alleged discharges of heated cooling water at Moss Landing.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse impact on PG&E Corporation's or the Utility's financial condition or results of operations.

Compressor Station Chromium Litigation

There are 15 civil actions pending in California courts against the Utility relating to alleged chromium contamination (Chromium Litigation): (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) *Monice v. Pacific Gas and Electric Company*, filed March 15, 2001, in San Bernardino County Superior Court, (8) *Fordyce v. Pacific Gas and Electric Company*, filed March 16, 2001, in San Bernardino Superior Court, (9) *Puckett v. Pacific Gas and Electric Company*, filed March 30, 2001, in Los Angeles County Superior Court, (10) *Alderson, et al. v. PG&E Corporation, Pacific Gas and Electric Company, Betz Chemical Company, et al.*, filed April 11, 2001, in Los Angeles County Superior Court, (11) *Bowers, et al. v. Pacific Gas and Electric Company, et al.* , filed April 20, 2001, in Los Angeles County Superior Court, (12) *Boyd, et al. v. Pacific Gas and Electric Company, et al.* , filed May 2, 2001, in Los Angeles County Superior Court, (13) *Martinez, et al. v. Pacific Gas and Electric Company* , filed June 29, 2001, in San Bernadino County Superior Court, (14) *Kearney v. Pacific Gas and Electric Company* , filed November 15, 2001, in Los Angeles County Superior Court, and (15) *Miller v. Pacific Gas and Electric Company* , filed November 21, 2001, in Los Angeles County Superior Court. The Utility has not yet been served with the complaints in the *Gale* , *Fordyce* , *Puckett* , *Alderson* , *Bowers* , *Boyd* , *Martinez* , *Kearney* or *Miller* cases. PG&E Corporation has also been named as a defendant in the *Alderson* and *Kearney* cases.

There are now approximately 1,290 plaintiffs in the Chromium Litigation. Each of the complaints alleges personal injuries and seeks compensatory and punitive damages in an unspecified amount arising out of alleged exposure to chromium contamination in the vicinity of the Utility's gas compressor stations located at Kettleman, Hinkley, and Topock, California. The plaintiffs include current and former employees of the Utility and their relatives, residents in the vicinity of the compressor stations, and persons who visited the gas compressor stations. The plaintiffs also include spouses or children of these plaintiffs who claim loss of consortium or wrongful death.

The discovery referee has set the procedures for selecting trial test plaintiffs and alternates in the *Aguayo* , *Acosta* , and *Aguilar* cases. Ten of these trial test plaintiffs were selected by plaintiffs' counsel, seven plaintiffs were selected by defense counsel, and one plaintiff and two alternates were selected at random. Although a date for the first test trial in these cases was set for July 2, 2001, in Los Angeles County Superior Court, the Chapter 11 case automatically stayed all proceedings.

Approximately 1,260 individuals have filed proofs of claim in the Utility's bankruptcy case (nearly all by plaintiffs in the Chromium Litigation) asserting that exposure to chromium at or near the compressor stations has caused personal injuries, wrongful death, or related damages. Approximately 1,035 claimants have filed proofs of claim requesting an approximate aggregate amount of $580 million and another approximately 225 claimants have filed claims for an "unknown amount." On November 14, 2001, the Utility filed objections to these claims and requested the Bankruptcy Court to transfer the chromium claims to the U. S. District Court. On January 8, 2002, the Bankruptcy Court denied the Utility's request to transfer the chromium claims and granted the claimants' motion for relief from stay so that the state court lawsuits pending before the Utility filed its bankruptcy petition can proceed.

Before April 6, 2001, when the Utility filed its bankruptcy petition, the Utility was responding to the complaints in which it had been served and asserting affirmative defenses. As of April 6, 2001, the Utility had filed 13 summary judgment motions challenging the claims of the trial test plaintiffs and completed discovery of plaintiffs' experts. Plaintiffs' discovery of the Utility's experts was underway. At this stage of the proceedings and the claims objections, there is substantial uncertainty concerning the claims alleged, and the Utility is attempting to gather information concerning the alleged type and duration of exposure, the nature of injuries alleged by individual plaintiffs, and the additional facts necessary to support its legal defenses, in order to better evaluate and defend this litigation and the proofs of claim filed.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse impact on PG&E Corporation's or the Utility's financial condition or results of operations. See Note 16 of the "Notes to Consolidated Financial Statements" of the 2001 Annual Report to Shareholders, portions of which are filed as Exhibit 13 to this report.

California Energy Trading Litigation

PG&E Corporation's indirect subsidiary, PG&E Energy Trading Holding Corporation, and one or more of its affiliates, have been named, along with multiple other defendants, in one or more four class action lawsuits against marketers and other unnamed sellers of electricity in California markets. These cases are (1) *Pier 23 Restaurant v. PG&E Energy Trading Corporation, et al.* , filed on January 24, 2001, in San Francisco Superior Court and subsequently removed to the United States District Court for the Northern District of California; (2) *Hendricks v. Dynegy Power Marketing, Inc., PG&E Energy Trading Corporation, et al.* , filed on November 29, 2000, in San Diego Superior Court and subsequently removed to the United States District Court for the Southern District of California; (3) *Sweetwater Authority v. Dynegy Inc., PG&E Energy Trading Corporation, et al.* , filed on January 16, 2001, in San Diego Superior Court and subsequently removed to the United States District Court for the Southern District of California; and (4) *People of the State of California v. Dynegy Power Marketing, Inc., PG&E Energy Trading Corporation, et al.* , filed on January 18, 2001, in San Francisco Superior Court and subsequently removed to the United States District Court for the Northern District of California.

In June 2001, the federal judicial panel on multi-district litigation assigned all the cases to the United States District Court for the Southern District of California where by order dated July 30, 2001, the district court judge remanded all of the cases to the state courts in which each of the cases was originally filed. Since that time, the cases have been assigned to a coordination trial judge in San Diego County Superior Court.

These suits allege violation by the defendants of state antitrust laws and state laws against unfair and unlawful business practices. Specifically, the named plaintiffs allege that the defendants, including the owners of in-state generation and various power marketers, conspired to manipulate the California wholesale power market to the detriment of California consumers. Included among the acts forming the basis of the plaintiffs' claims are the alleged improper sharing of generation outage data, improper withholding of generation capacity, and the manipulation of power market bid practices. The plaintiffs seek unspecified treble damages and, among other remedies, disgorgement of alleged unlawful profits for sales of electricity beginning in 1999 or 2000, restitution, injunctive relief, and attorneys' fees.

PG&E Corporation believes that the ultimate outcome of this matter will not have a material adverse impact on its financial condition or results of operations.

California Attorney General Complaint

On January 10, 2002, the California Attorney General (AG) filed a complaint in the San Francisco Superior Court against PG&E Corporation and its directors, as well as against the directors of the Utility, based on allegations of unfair or fraudulent business acts or practices in violation of California Business and Professions (B&P) Code Section 17200. Among other allegations, the AG alleges that past transfers of money from the Utility to PG&E Corporation, and allegedly from PG&E Corporation to other affiliates of PG&E Corporation, violated various conditions established by the CPUC in decisions approving the holding company formation. The AG also alleges that the December 2000 and January and February 2001 ringfencing transactions, by which PG&E Corporation subsidiaries complied with credit rating agency criteria to establish independent credit ratings, violated the holding company conditions. The AG alleges that these ringfencing transactions included conditions that restricted PG&E NEG's ability to provide any funds to PG&E Corporation, through dividends, capital distributions or similar payments, reducing PG&E Corporation's cash and thereby impairing PG&E Corporation's ability to comply with the first priority condition and subordinating the Utility's interests to the interests of PG&E Corporation and its other affiliates. (On January 9, 2002, the CPUC issued a decision interpreting 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. (See "Regulation of PG&E Corporation" above.))

The ringfencing transactions were approved by the FERC on January 12, 2001. Thereafter, requests for rehearing and requests to vacate that order were filed with the FERC, each of which was denied by the FERC on February 21, 2001. Requests for rehearing of the February 21 order were then filed. On January 30, 2002, the FERC issued an order denying all pending petitions for rehearing. On February 21, 2002, the AG appealed the FERC's January 30 order to the United States Court of Appeals for the Ninth Circuit.

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

In addition, the AG alleges that, through the Utility's bankruptcy proceedings, PG&E Corporation and the Utility engaged in unlawful, unfair, and fraudulent business practices by seeking to implement the transactions proposed in the proposed plan of reorganization filed in the Utility's bankruptcy proceeding. The AG's complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from the Utility. The Bankruptcy Court has original and exclusive jurisdiction of these claims. Therefore, on February 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the AG's complaint to the Bankruptcy Court.

On February 15, 2002, a motion to dismiss, or in the alternative, to stay, the complaint was filed in the Bankruptcy Court.

PG&E Corporation believes that the allegations of the complaint are without merit and will vigorously respond to and defend the litigation. PG&E Corporation is unable to predict whether the outcome of this litigation will have a material adverse affect on its financial condition or results of operation.

Complaint filed by the City and County of San Francisco, and the People of the State of California

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 AG's complaint including allegations of unfair competition in violation of B&P Code Section 17200. In addition, the complaint alleges causes of action for conversion, claiming that PG&E Corporation "took at least $5.2 billion from PG&E," and for unjust enrichment.

Among other allegations, plaintiffs allege that past transfers of money from the Utility to PG&E Corporation, and allegedly used by PG&E Corporation to subsidize other affiliates of PG&E Corporation, violated various conditions established by the CPUC in decisions approving the holding company formation. The complaint also alleges that certain ring-fencing transactions by which PG&E Corporation subsidiaries complied with credit rating agency criteria to establish independent credit ratings violated the holding company conditions. Plaintiffs also allege that by agreeing to certain restrictive covenants in certain financing agreements, PG&E Corporation also violated a holding company condition.

Plaintiffs seek injunctive relief, the appointment of a receiver, restitution, disgorgement, the imposition of a constructive trust, civil penalties of $2,500 against each defendant for each violation of B&P Code Section 17200 as authorized by B&P Code Section 17206, and costs of suit.

PG&E Corporation believes that the allegations of the complaint are without merit and will vigorously respond to and defend the litigation. PG&E Corporation is unable to predict whether the outcome of this litigation will have a material adverse affect on its financial condition or results of operation.

Sierra Pacific Industries v. Pacific Gas and Electric Company

On April 2, 2001, Sierra Pacific Industries, Inc. (SPI), a qualifying facility (QF) generator, sued the Utility and the ISO alleging various contract, tort, unfair business practice, and antitrust claims against the defendants. SPI claims the Utility breached four PPAs with SPI by making only partial payments for SPI's December 2000

through March 2001 energy deliveries. In addition, SPI claims the Utility and the ISO conspired to prevent SPI from terminating the PPAs and selling its power into the California wholesale energy markets. SPI's claims for tortious interference, unfair business practices, and antitrust claims are based on this alleged conspiracy.

On April 5, 2001, the Sacramento Superior Court issued a temporary restraining order to allow SPI to sell power into the spot market rather than to the Utility. On April 24, 2001, the Utility removed SPI's case to federal court and the parties stipulated to transferring venue to the Bankruptcy Court.

On May 21, 2001, the Bankruptcy Court granted SPI's preliminary injunction motion allowing it to continue to sell power into the market. On September 1, 2001, the Bankruptcy Court granted SPI's motion for partial summary judgment finding that SPI terminated its PPAs on March 29, 2001, before the Utility filed its bankruptcy petition on April 6, 2001, and that SPI is not liable for contractual "minimum damages" for early termination. On November 21, 2001, the Bankruptcy Court remanded SPI's lawsuit to the Sacramento Superior Court to liquidate SPI's claims. The parties are now involved in discovery and motion practice.

SPI filed a $1.1 billion proof of claim in the Utility's bankruptcy proceeding seeking (1) $17.8 million for unpaid pre-petition energy deliveries, (2) $89.1 million for lost profits under its contract, tort and antitrust theories, and (3) $1 billion in punitive damages under its tort theory. In addition, SPI claims it is entitled to treble damages for antitrust violations and lost profits and punitive damages for the Utility's alleged violation of California Public Utilities Code Section 2106.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse impact on their financial condition or results of operations.

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

On February 27, 2002, a group of 25 ratepayers filed a complaint against the Utility at the CPUC demanding an immediate reduction of approximately 3.5 cents per kWh in allegedly excessive electric rates and a refund of alleged recent overcollections in electric revenue since June 1, 2001. The complaint claims that electric rate surcharges adopted in the first quarter of 2001 due to the high cost of wholesale power, surcharges that increased the average electric rate by 4.0 cents per kWh, became excessive later in 2001. (In January 2001, the CPUC authorized a 1 cent per kWh rate increase to pay for energy procurement costs. In March 2001, the CPUC authorized an additional 3.0 cent per kWh rate increase as of March 27, 2001, to pay for energy procurement costs, which the Utility began to collect in June 2001.) The only alleged over collection amount calculated in the complaint is approximately $400 million during the last quarter of 2001. The complaint has not yet been served on the Utility. The Utility's answer will be due 30 days after the date of service of the complaint.

ITEM 4. Submission of Matters to a Vote of Security Holders.

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANTS

"Executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Securities and Exchange Act of 1934, of PG&E Corporation are as follows:

Name	Age at December 31, 2001	Position
R. D. Glynn, Jr.	59	Chairman of the Board, Chief Executive Officer, and President
T. G. Boren	52	Executive Vice President; Chairman, President, and Chief Executive Officer, PG&E National Energy Group, Inc.
P. A. Darbee	49	Senior Vice President and Chief Financial Officer
P. C. Iribe	51	Senior Vice President; President and Chief Operating Officer, East Region, PG&E National Energy Group, Inc.
C. P. Johns	41	Senior Vice President and Controller
T. B. King	40	Senior Vice President; President and Chief Operating Officer, West Region, PG&E National Energy Group, Inc.
L. E. Maddox	46	Senior Vice President; President and Chief Operating Officer, Trading, PG&E National Energy Group, Inc.
G. R. Smith	53	Senior Vice President; President and Chief Executive Officer, Pacific Gas and Electric Company
G. B. Stanley	55	Senior Vice President, Human Resources
B. R. Worthington	52	Senior Vice President and General Counsel

All officers of PG&E Corporation serve at the pleasure of the Board of Directors. During the past five years, the executive officers of PG&E Corporation had the following business experience. Except as otherwise noted, all positions have been held at PG&E Corporation.

Name	Position	Period Held Office
R. D. Glynn, Jr.	Chairman of the Board, Chief Executive Officer, and President	January 1, 1998 to present
	Chairman of the Board, Pacific Gas and Electric Company	January 1, 1998 to present
	President and Chief Executive Officer	June 1, 1997 to December 31, 1997
	President and Chief Operating Officer	December 18, 1996 to May 31, 1997
	President and Chief Operating Officer, Pacific Gas and Electric Company	June 1, 1995 to May 31, 1997
T. G. Boren	Executive Vice President	August 1, 1999 to present
	Chairman, President,and Chief Executive Officer, PG&E National Energy Group, Inc.	July 1, 2000 to present
	President and Chief Executive Officer, PG&E National Energy Group, Inc.	August 1, 1999 to June 30, 2000
	President and Chief Executive Officer, Southern Energy, Inc.	February 18, 1992 to July 31, 1999
	Executive Vice President, Southern Company	June 1, 1999 to July 31, 1999
	Senior Vice President, Southern Company	February 16, 1998 to May 31, 1999
	Vice President, Southern Company	July 17, 1995 to February 15, 1998

Name	Position	Period Held Office
P. A. Darbee	Senior Vice President and Treasurer	July 9, 2001 to present
	Senior Vice President, Chief Financial Officer, and Treasurer	September 20, 1999 to July 8, 2001
	Vice President and Chief Financial Officer, Advance Fibre Communications, Inc.	June 30, 1997 to September 19, 1999
	Vice President, Chief Financial Officer, and Controller, Pacific Bell	January 10, 1994 to June 30, 1997
P. C. Iribe	Senior Vice President	January 1, 1999 to present
	President and Chief Operating Officer, East Region, PG&E National Energy Group, Inc.	July 1, 2000 to present
	President and Chief Operating Officer, PG&E National Energy Group Company (formerly known as PG&E Generating Company)	November 1, 1998 to present
	Executive Vice President and Chief Operating Officer, U.S. Generating Company	September 1, 1997 to October 31, 1998
	Executive Vice President, Marketing, Development, and Asset Management, U.S. Generating Company	May 17, 1994 to September 1, 1997
C. P. Johns	Senior Vice President and Controller	September 19, 2001 to present
	Vice President and Controller	July 1, 1997 to September 18, 2001
	Controller	December 18, 1996 to June 30, 1997
	Vice President and Controller, Pacific Gas and Electric Company	April 17, 1996 to December 31, 1999
T. B. King	Senior Vice President	January 1, 1999 to present
	President and Chief Operating Officer, West Region, PG&E National Energy Group, Inc.	July 1, 2000 to present
	President and Chief Operating Officer, PG&E Gas Transmission Corporation	November 23, 1998 to present
	President and Chief Operating Officer, Kinder Morgan Energy Partners, L.P.	February 14, 1997 to November 22, 1998
	Vice President, Commercial Operations—Midwest Region, Enron Liquid Services Corporation	July 1, 1995 to February 14, 1997
L. E. Maddox	Senior Vice President	June 1, 1997 to present
	President and Chief Operating Officer, Trading, PG&E National Energy Group, Inc.	July 1, 2000 to present
	President and Chief Executive Officer, PG&E Energy Trading-Gas Corporation	May 12, 1997 to present
	President, PennUnion Energy Services, L.L.C.	May 1995 to May 1997
G. R. Smith	Senior Vice President (Please refer to description of business experience for executive officers of Pacific Gas and Electric Company below.)	January 1, 1999 to present
G. B. Stanley	Senior Vice President, Human Resources	January 1, 1998 to present
	Vice President, Human Resources	June 1, 1997 to December 31, 1997
	Vice President, Human Resources, Pacific Gas and Electric Company	July 1, 1996 to May 31, 1997
B. R. Worthington	Senior Vice President and General Counsel	June 1, 1997 to present
	General Counsel	December 18, 1996 to May 31, 1997
	Senior Vice President and General Counsel, Pacific Gas and Electric Company	June 1, 1995 to June 30, 1997

"Executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Securities and Exchange Act of 1934, of Pacific Gas and Electric Company are as follows:

Name	Age at December 31, 2001	Position
G. R. Smith	53	President and Chief Executive Officer
K. M. Harvey	43	Senior Vice President, Chief Financial Officer, and Treasurer
R. J. Peters	47	Senior Vice President and General Counsel
J. K. Randolph	57	Senior Vice President and Chief of Utility Operations
D. D. Richard, Jr.	51	Senior Vice President, Public Affairs
G. M. Rueger	51	Senior Vice President, Generation and Chief Nuclear Officer

All officers of Pacific Gas and Electric Company serve at the pleasure of the Board of Directors. During the past five years, the executive officers of Pacific Gas and Electric Company had the following business experience. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

Name	Position	Period Held Office
G. R. Smith	President and Chief Executive Officer	June 1, 1997 to present
	Chief Financial Officer, PG&E Corporation	December 18, 1996 to May 31, 1997
	Senior Vice President and Chief Financial Officer	June 1, 1995 to May 31, 1997
K. M. Harvey	Senior Vice President, Chief Financial Officer, and Treasurer	November 1, 2000 to present
	Senior Vice President, Chief Financial Officer, Controller, and Treasurer	January 1, 2000 to October 31, 2000
	Senior Vice President, Chief Financial Officer, and Treasurer	July 1, 1997 to December 31, 1999
	Vice President and Treasurer	June 1, 1995 to June 30, 1997
R. J. Peters	Senior Vice President and General Counsel	January 1, 1999 to present
	Vice President and General Counsel	July 1, 1997 to December 31, 1998
	Chief Counsel, Regulatory	January 1, 1993 to June 30, 1997
J. K. Randolph	Senior Vice President and Chief of Utility Operations	April 6, 2000 to present
	Senior Vice President and General Manager, Transmission, Distribution and Customer Service Business Unit	January 24, 2000 to April 5, 2000
	Senior Vice President and General Manager, Distribution and Customer Service Business Unit	July 1, 1997 to January 23, 2000
	Vice President and General Manager, Power Generation Business Unit	January 1, 1997 to June 30, 1997
D. D. Richard, Jr.	Senior Vice President, Public Affairs	May 1, 1998 to present
	Senior Vice President, Governmental and Regulatory Relations	July 1, 1997 to April 30, 1998
	Senior Vice President, Public Affairs, PG&E Corporation	October 18, 2000 to present
	Vice President, Governmental Relations, PG&E Corporation	July 1, 1997 to October 17, 2000
	Vice President, Governmental Relations	January 1, 1997 to June 30, 1997
G. M. Rueger	Senior Vice President, Generation and Chief Nuclear Officer	April 6, 2000 to present
	Senior Vice President and General Manager, Nuclear Power Generation Business Unit	November 1, 1991 to April 5, 2000

PART II

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

Information responding to part of Item 5, for each of PG&E Corporation and Pacific Gas and Electric Company, is set forth on page 125 under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 2001 Annual Report to Shareholders, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report. As of February 14, 2002, there were 124,405 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York, Pacific, and Swiss stock exchanges. The discussion of dividends with respect to PG&E Corporation's common stock is hereby incorporated by reference from "Management's Discussion and Analysis—Dividends" on page 36 of the 2001 Annual Report to Shareholders.

Neither Pacific Gas and Electric Company nor PG&E Corporation made any sales of unregistered equity securities during 2001, the period covered by this report.

ITEM 6. Selected Financial Data.

A summary of selected financial information, for each of PG&E Corporation and Pacific Gas and Electric Company for each of the last five fiscal years, is set forth on page 8 under the heading "Selected Financial Data" in the 2001 Annual Report to Shareholders, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Pacific Gas and Electric Company's ratio of earnings to fixed charges for the year ended December 31, 2001 was 2.58. Pacific Gas and Electric Company's ratio of earnings to combined fixed charges and preferred stock dividends for the year ended December 31, 2001 was 2.49. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and exhibits into Registration Statement Nos. 33-62488, 33-64136, 33-50707, and 33-61959 relating to Pacific Gas and Electric Company's various classes of debt and first preferred stock outstanding.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

A discussion of PG&E Corporation's and Pacific Gas and Electric Company's consolidated results of operations and financial condition is set forth on pages 9 through 57 under the heading "Management's Discussion and Analysis" in the 2001 Annual Report to Shareholders, which discussion is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk.

Information responding to Item 7A appears in the 2001 Annual Report to Shareholders on pages 50-55 under the heading "Management's Discussion and Analysis—Quantitative and Qualitative Disclosures about Market Risk," and on pages 74-76, 87-89 and 95-99 under Notes 1, 4, 9, and 10 of the "Notes to the Consolidated Financial Statements" of the 2001 Annual Report to Shareholders, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

ITEM 8. Financial Statements and Supplementary Data.

Information responding to Item 8 appears on pages 58 through 127 of the 2001 Annual Report to Shareholders under the following headings for PG&E Corporation: "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Common Stockholders' Equity"; under the following headings for Pacific Gas and Electric Company: "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Stockholders' Equity;" and under the following headings for PG&E Corporation and

Pacific Gas and Electric Company jointly: “Notes to the Consolidated Financial Statements,” “Quarterly Consolidated Financial Data (Unaudited),” “Independent Auditors’ Report,” and “Responsibility for the Consolidated Financial Statements,” which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

Not applicable.

PART III

ITEM 10. Directors and Executive Officers of the Registrant.

Information regarding executive officers of PG&E Corporation and Pacific Gas and Electric Company is included in a separate item captioned “Executive Officers of the Registrant” contained on pages 71 through 73 in Part I of this report. Other information responding to Item 10 is included under the heading “Item No. 1: Election of Directors of PG&E Corporation and Pacific Gas and Electric Company” and under the heading “Section 16 Beneficial Ownership Reporting Compliance” in the Joint Proxy Statement relating to the 2002 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

ITEM 11. Executive Compensation.

Information responding to Item 11, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading “Compensation of Directors” and under the headings “Summary Compensation Table,” “Option/SAR Grants in 2001” “Aggregated Option/SAR Exercises in 2001 and Year-End Option/SAR Values,” “Long-Term Incentive Plan—Awards in 2001,” “Retirement Benefits,” “Employment Contracts/Arrangements,” and “Termination of Employment and Change In Control Provisions” in the Joint Proxy Statement relating to the 2002 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management.

Information responding to Item 12, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading “Security Ownership of Management” and under the heading “Principal Shareholders” in the Joint Proxy Statement relating to the 2002 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

ITEM 13. Certain Relationships and Related Transactions.

Information responding to Item 13, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading “Certain Relationships and Related Transactions” in the Joint Proxy Statement relating to the 2002 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

PART IV

ITEM 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K.

(a) The following documents are filed as a part of this report:

1. The following consolidated financial statements, supplemental information, and independent auditors' report are contained in the 2001 Annual Report to Shareholders, which have been incorporated by reference in this report:

   Consolidated Statements of Operations for the Years Ended December 31, 2001, 2000, and 1999, for each of PG&E Corporation and Pacific Gas and Electric Company.

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2001, 2000, and 1999, for each of PG&E Corporation and Pacific Gas and Electric Company.

   Consolidated Balance Sheets at December 31, 2001 and 2000 for each of PG&E Corporation and Pacific Gas and Electric Company.

   Consolidated Statements of Common Stockholders' Equity for the Years Ended December 31, 2001, 2000, and 1999, for PG&E Corporation.

   Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2001, 2000 and 1999 for Pacific Gas and Electric Company.

   Notes to Consolidated Financial Statements.

   Quarterly Consolidated Financial Data (Unaudited).

   Independent Auditors' Report (Deloitte & Touche LLP).

2. Independent Auditors' Report (Deloitte & Touche LLP) included at page 84 of this Form 10-K.

3. Financial statement schedules:

   I—Condensed Financial Information of Parent for the Years Ended December 31, 2001, 2000 and 1999.

   II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2001, 2000, and 1999.

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements including the notes thereto.

6. Exhibits required to be filed by Item 601 of Regulation S-K:

   3.1 Restated Articles of Incorporation of PG&E Corporation effective as of May 5, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (File No. 1-12609), Exhibit 3.1)

   3.2 Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2)

   3.3 Bylaws of PG&E Corporation amended as of February 21, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.3)

3.4 Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of May 6, 1998 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-2348), Exhibit 3.1)

3.5 Bylaws of Pacific Gas and Electric Company amended as of February 21, 2001 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-2348), Exhibit 3.5)

4.1 First and Refunding Mortgage of Pacific Gas and Electric Company dated December 1, 1920, and supplements thereto dated April 23, 1925, October 1, 1931, March 1, 1941, September 1, 1947, May 15, 1950, May 1, 1954, May 21, 1958, November 1, 1964, July 1, 1965, July 1, 1969, January 1, 1975, June 1, 1979, August 1, 1983, and December 1, 1988 (incorporated by reference to Registration No. 2-1324, Exhibits B-1, B-2, and B-3; Registration No. 2-4676, Exhibit B-22; Registration No. 2-7203, Exhibit B-23; Registration No. 2-8475, Exhibit B-24; Registration No. 2-10874, Exhibit 4B; Registration No. 2-14144, Exhibit 4B; Registration No. 2-22910, Exhibit 2B; Registration No. 2-23759, Exhibit 2B; Registration No. 2-35106, Exhibit 2B; Registration No. 2-54302, Exhibit 2C; Registration No. 2-64313, Exhibit 2C; Registration No. 2-86849, Exhibit 4.3; and Pacific Gas and Electric Company's Form 8-K dated January 18, 1989 (File No. 1-2348), Exhibit 4.2)

In accordance with Item 601(b)(4)(iii) of Regulation S-K, each of PG&E Corporation or Pacific Gas and Electric Company agrees to furnish to the Commission any instruments respecting long-term debt not required to be filed by application of such item.

4.2 Form of Rights Agreement dated as of December 22, 2000, between PG&E Corporation and Mellon Investor Services LLC, including the Form of Rights Certificate as Exhibit A, the Summary of Rights to Purchase Preferred Stock as Exhibit B, and the Form of Certificate of Determination of Preferences for the Preferred Stock as Exhibit C (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 4.2)

10 The Gas Accord Settlement Agreement, together with accompanying tables, adopted by the California Public Utilities Commission on August 1, 1997, in Decision 97-08-055 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 1997 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2), as amended by Operational Flow Order (OFO) Settlement Agreement, approved by the California Public Utilities Commission on February 17, 2000, in Decision 00-02-050, as amended by Comprehensive Gas OII Settlement Agreement, approved by the California Public Utilities Commission on May 18, 2000, in Decision 00-05-049 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10)

10.1 Credit Agreement between PG&E Corporation, General Electric Capital Corporation, and Lehman Commercial Paper, Inc. dated March 1, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.2)

10.2 First Amendment to Credit Agreement between PG&E Corporation, General Electric Capital Corporation, and Lehman Commercial Paper, Inc. dated November 19, 2001.

10.3 Amended and Restated Credit Agreement among PG&E National Energy Group, Inc. and Chase Manhattan Bank dated August 22, 2001.

*10.4 PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001.

*10.5 Description of Compensation Arrangement between PG&E Corporation and Thomas G. Boren (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.2)

*10.6 Description of Compensation Arrangement between PG&E Corporation and Peter Darbee (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.3)

*10.7 Letter regarding Compensation Arrangement between PG&E Corporation and Thomas B. King dated November 4, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.6)

*10.8 Letter regarding Compensation Arrangement between PG&E Corporation and Lyn E. Maddox dated April 25, 1997 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.7)

*10.9 Letter Regarding Relocation Arrangement Between PG&E Corporation and Thomas B. King dated March 16, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (File No. 1-12609), Exhibit 10)

*10.10 Description of Relocation Arrangement Between PG&E Corporation and Lyn E. Maddox (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.9)

*10.11 PG&E Corporation Senior Executive Officer Retention Program approved December 20, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10)

*10.11.1 Letter regarding retention award to Robert D. Glynn, Jr. dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.1)

*10.11.2 Letter regarding retention award to Gordon R. Smith dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.2)

*10.11.3 Letter regarding retention award to Peter A. Darbee dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.3)

*10.11.4 Letter regarding retention award to Bruce R. Worthington dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.4)

*10.11.5 Letter regarding retention award to G. Brent Stanley dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.5)

*10.11.6 Letter regarding retention award to Daniel D. Richard dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.6)

*10.11.7 Letter regarding retention award to James K Randolph dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.7)

*10.11.8 Letter regarding retention award to Gregory M. Rueger dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.8)

*10.11.9 Letter regarding retention award to Kent Harvey dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.9)

*10.11.10 Letter regarding retention award to Roger J. Peters dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.10))

*10.11.11 Letter regarding retention award to Thomas G. Boren dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.11)

*10.11.12 Letter regarding retention award to Lyn E. Maddox dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.12)

*10.11.13 Letter regarding retention award to P. Chrisman Iribe dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.13)

*10.11.14 Letter regarding retention award to Thomas B. King dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.14)

*10.12 Pacific Gas and Electric Company Management Retention Program (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609), Exhibit 10.1)

*10.13 PG&E Corporation Management Retention Program (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609), Exhibit 10.2)

*10.14 PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2)

*10.15 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.14)

*10.16 Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended as of September 19, 2001.

*10.17 Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1989 (File No. 1-2348), Exhibit 10.16)

*10.18 Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1991 (File No. 1-2348), Exhibit 10.16)

*10.19	PG&E Corporation Retirement Plan for Non-Employee Directors, as amended and terminated January 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1997 (File No. 1-12609), Exhibit 10.13)
*10.20	PG&E Corporation Long-Term Incentive Program, as amended May 16, 2001, including the PG&E Corporation Stock Option Plan, Performance Unit Plan, and Non- Employee Director Stock Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)
*10.21	PG&E Corporation Executive Stock Ownership Program, amended as of September 19, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.20)
*10.22	PG&E Corporation Officer Severance Policy, amended as of July 21, 1999 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.1)
*10.23	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
*10.24	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.2)
*10.25	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2002.
11	Computation of Earnings Per Common Share
12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
13	2001 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company—portions of the Report to Shareholders under the headings "Selected Financial Data," "Management's Discussion and Analysis," "Independent Auditors' Report," "Responsibility for Consolidated Financial Statements," financial statements of PG&E Corporation entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Common Stockholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," "Consolidated Statements of Stockholders' Equity," "Notes to Consolidated Financial Statements," and "Quarterly Consolidated Financial Data (Unaudited)" are included only
21	Subsidiaries of the Registrant
23	Independent Auditors' Consent (Deloitte & Touche LLP)
24.1	Resolutions of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company authorizing the execution of the Form 10-K
24.2	Powers of Attorney

* Management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

The exhibits filed herewith are attached hereto (except as noted) and those indicated above which are not filed herewith were previously filed with the Commission and are hereby incorporated by reference. All exhibits filed herewith or incorporated by reference are filed with respect to both PG&E Corporation (File No. 1-12609) and Pacific Gas and Electric Company (File No. 1-2348), unless otherwise noted. Exhibits will be furnished to security holders of PG&E Corporation or Pacific Gas and Electric Company upon written request and payment of a fee of $0.30 per page, which fee covers only the registrants' reasonable expenses in furnishing such exhibits. The registrants agree to furnish to the Commission upon request a copy of any instrument defining the rights of long-term debt holders not otherwise required to be filed hereunder.

(b) Reports on Form 8-K

Reports on Form 8-K(1) during the quarter ended December 31, 2001, and through the date hereof:

1. October 2, 2001

Item 5. Other Events

Item 7. Financial Statements, Pro Forma Financial Information, and Exhibits

Exhibit 99—Pacific Gas and Electric Company Income Statement for the month ended August 31, 2001, and Balance Sheet dated August 31, 2001

2. October 25, 2001

Item 5. Other Events

Pacific Gas and Electric Company's 1999 General Rate Case Proceeding

3. November 1, 2001

Item 5. Other Events

A. Pacific Gas and Electric Company's 2002 General Rate Case Proceeding
B. Pacific Gas and Electric Company's Retained Generation Ratemaking Proceeding

4. November 30, 2001

Item 5. Other Events

5. December 3, 2001 (as amended by Form 8-K/A filed December 6, 2001)

Item 5. Other Events

A. Pacific Gas and Electric Company Bankruptcy
B. Amendment of PG&E Corporation Credit Agreement
C. Exposure to Enron Corporation

Item 7. Financial Statements, Pro Forma Financial Information, and Exhibits

Exhibit 99.1—Pacific Gas and Electric Company Income Statement for the month ended October 31, 2001, and Balance Sheet dated October 31, 2001

Exhibit 9.2—Financial Projections and Underlying Assumptions related to proposed Plan of Reorganization

6. December 28, 2001

Item 5. Pacific Gas and Electric Company Bankruptcy

Item 7. Financial Statements, Pro Forma Financial Information, and Exhibits

Exhibit 99.1—Pacific Gas and Electric Company Income Statement for the month ended November 30, 2001, and Balance Sheet dated November 30, 2001.

7. January 11, 2002

Item 5.

A. CPUC Order Instituting Investigation into Holding Company Activities
B. California Attorney General Complaint
C. Pacific Gas and Electric Company Bankruptcy – CPUC Motion to Extend Exclusivity Period

8. January 14, 2002

Item 5. Pacific Gas and Electric Company Bankruptcy—Agreement with Ad Hoc Committee

9. January 18, 2002

Item 5.

A. Pacific Gas and Electric Company Bankruptcy
B. Pacific Gas and Electric Company's Filing of Claim with State of California Victim Compensation and Government Claims Board

10. January 31, 2002

Item 5.

A. Pacific Gas and Electric Company—Utility Retained Generation Ratemaking

11. February 13, 2002

Item 5.

A. Pacific Gas and Electric Company Bankruptcy
B. California Attorney General Complaint
C. Complaint filed by the City and County of San Francisco, and the People of the State of California

12. February 28, 2002

Item 5.

A. Pacific Gas and Electric Company Bankruptcy
B. 2001 Attrition Rate Adjustment
C. Allocation of California Department of Water Resources' Revenue Requirements
D. PG&E National Energy Group Synthetic Leases

(1) Unless otherwise noted, all reports were filed under Commission File Number 1-2348 (Pacific Gas and Electric Company) and Commission File Number 1-12609 (PG&E Corporation).

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized, in the City and County of San Francisco, on the 5th day of March, 2002.

PG&E CORPORATION
(Registrant)
GARY P. ENCINAS
By _____
(Gary P. Encinas, Attorney-in-Fact)

PACIFIC GAS AND ELECTRIC COMPANY
(Registrant)
GARY P. ENCINAS
By _____
(Gary P. Encinas, Attorney-in-Fact)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.

Signature	Title	Date
A. Principal Executive Officers		
*ROBERT D. GLYNN, JR.	Chairman of the Board, Chief Executive Officer, and President (PG&E Corporation)	March 5, 2002
*GORDON R. SMITH	President and Chief Executive Officer (Pacific Gas and Electric Company)	March 5, 2002
B. Principal Financial Officers		
*PETER A. DARBEE	Senior Vice President and Chief Financial Officer (PG&E Corporation)	March 5, 2002
*KENT M. HARVEY	Senior Vice President, Chief Financial Officer, and Treasurer (Pacific Gas and Electric Company)	March 5, 2002
C. Principal Accounting Officers		
*CHRISTOPHER P. JOHNS	Senior Vice President and Controller (PG&E Corporation)	March 5, 2002
*DINYAR B. MISTRY	Vice President-Controller (Pacific Gas and Electric Company)	March 5, 2002
D. Directors		
*DAVID R. ANDREWS *DAVID A. COULTER *C. LEE COX *WILLIAM S. DAVILA *ROBERT D. GLYNN, JR. *DAVID M. LAWRENCE, M.D. *MARY S. METZ *CARL E. REICHARDT *GORDON R. SMITH (Director of Pacific Gas and Electric Company only) *BARRY LAWSON WILLIAMS	Directors of PG&E Corporation and Pacific Gas and Electric Company, except as noted	March 5, 2002

GARY P. ENCINAS
*By _____
(Gary P. Encinas, Attorney-in-Fact)

INDEPENDENT AUDITORS' REPORT

To the Shareholders and the Boards of Directors of
PG&E Corporation and Pacific Gas and Electric Company:

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries and Pacific Gas and Electric Company (a Debtor-in-Possession) and subsidiaries as of and for the years ended December 31, 2001 and 2000, and for each of the three years in the period ended December 31, 2001 and have issued our report thereon dated March 1, 2002, which report includes an explanatory paragraph concerning the ability of Pacific Gas and Electric Company to continue as a going concern; such consolidated financial statements are included in your 2001 Annual Report to Shareholders and are incorporated herein by reference. Our audits also included the financial statement schedules of PG&E Corporation and Pacific Gas and Electric Company (a Debtor-in-Possession), listed in Item 14(a)3. These financial statement schedules are the responsibility of the management of PG&E Corporation and Pacific Gas and Electric Company. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP

San Francisco, California
March 1, 2002

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF PARENT

CONDENSED BALANCE SHEETS

	December 31,	
	2001	2000
	(in millions)	
Assets:		
Cash and cash equivalents	$ 348	$ 351
Advances to affiliates	404	295
Note receivable from subsidiary	308	308
Other current assets	1	6
Total current assets	1,061	960
Equipment	19	15
Accumulated depreciation	(9)	(6)
Net equipment	10	9
Investments in subsidiaries	4,595	3,439
Other investments	61	64
Deferred income taxes	42	—
Other	57	1
Total Assets	$ 5,826	$ 4,473
Liabilities and Stockholders' Equity:		
Current Liabilities:		
Short-term borrowings	$ —	$ 931
Accounts payable—related parties	22	59
Accounts payable—trade	17	13
Note payable to subsidiary	75	75
Accrued taxes	309	108
Dividends payable	—	109
Other	25	25
Total current liabilities	448	1,320
Noncurrent Liabilities:		
Long-term debt	904	—
Deferred income taxes	—	9
Other	182	10
Total noncurrent liabilities	1,086	19
Stockholders' Equity:		
Common stock	5,986	5,971
Common stock held by subsidiary	(690)	(690)
Reinvested earnings	(1,004)	(2,147)
Total stockholders' equity	4,292	3,134
Total Liabilities and Stockholders' Equity	$ 5,826	$ 4,473

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF PARENT—(Continued)

CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 2001, 2000, and 1999

	2001	2000	1999
	(in millions except per share amounts)		
Administrative service revenue	$ 95	$ 111	$ 82
Equity in earnings (losses) of subsidiaries	1,144	(3,316)	853
Operating expenses	(108)	(111)	(86)
Loss on assets held for sale	—	—	(1,275)
Interest income	35	20	12
Interest expense	(132)	(27)	(30)
Other income	4	2	4
Income (Loss) Before Income Taxes	1,038	(3,321)	(440)
Less: Income Taxes	(52)	(4)	(447)
Income (Loss) from continuing operations	1,090	(3,317)	7
Discontinued operations	—	(40)	(98)
Cumulative effect of a change in an accounting principle	9	—	12
Net income (loss) before intercompany elimination	1,099	(3,357)	(79)
Eliminations of intercompany (profit) loss	—	(7)	6
Net income (loss)	$ 1,099	$ (3,364)	$ (73)
Weighted Average Common Shares Outstanding	363	362	368
Earnings (Loss) Per Common Share, Basic	$ 3.03	$ (9.29)	$ (0.20)
Earnings (Loss) Per Common Share, Diluted	$ 3.02	$ (9.29)	$ (0.20)

CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2001, 2000, and 1999

	2001	2000	1999
		(in millions)	
Cash Flows from Operating Activities:			
Net income (loss)	$ 1,099	$ (3,364)	$ (73)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Equity in earnings of subsidiaries	(1,143)	3,316	(853)
Deferred taxes	(51)	20	(415)
Loss on assets held for sale	—	—	1,275
Distributions from consolidated subsidiaries	—	475	527
Other-net	218	232	77
Net cash provided by operating activities	$ 123	$ 679	$ 538
Cash Flows From Investing Activities:			
Capital expenditures	(4)	1	(8)
Investment in subsidiaries	—	(555)	(722)
Loans to subsidiaries	—	(308)	—
Return of capital by Utility (share repurchases)	—	275	926
Other-net	—	(9)	(12)
Net cash provided (used) by investing activities	$ (4)	$ (596)	$ 184
Cash Flows From Financing Activities:			
Common stock issued	15	65	54
Common stock repurchased	(1)	(2)	(3)
Loans from subsidiary	—	75	—
Long-term debt issued	904	—	—
Short-term debt issued (redeemed)	(931)	405	(157)
Dividends paid	(109)	(436)	(465)
Other-net	—	6	(5)
Net cash provided (used) by financing activities	$ (122)	$ 113	$ (576)
Net Change in Cash & Cash Equivalents	(3)	196	146
Cash & Cash Equivalents at January 1	351	155	9
Cash & Cash Equivalents at December 31	$ 348	$ 351	$ 155

PG&E CORPORATION

SCHEDULE II—CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2001, 2000, and 1999

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
Valuation and qualifying accounts deducted from assets:					
2001:					
Allowance for uncollectible accounts (2)	$ 71	$ 82	$ —	$ 64(1)	$ 89
Provision for loss on generation-related regulatory assets and undercollected purchased power costs (3)	$ 6,939	$ —	$ —	$ 6,939	$ —
2000:					
Allowance for uncollectible accounts (2)	$ 65	$ 48	$ 2	$ 44(1)	$ 71
Provision for loss on generation-related regulatory assets and undercollected purchased power costs (3)	$ —	$ 6,939	$ —	$ —	$ 6,939
1999:					
Allowance for uncollectible accounts (2)	$ 59	$ 25	$ —	$ 19(1)	$ 65

(1) Deductions consist principally of write-offs, net of collections of receivables previously written off.

(2) Allowance for uncollectible accounts are deducted from “Accounts receivable Customers, net” and “Accounts receivable Energy Marketing.”

(3) Provision was deducted from “Regulatory Assets.”

PACIFIC GAS AND ELECTRIC COMPANY
A DEBTOR-IN-POSSESSION

SCHEDULE II—CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2001, 2000, and 1999

Column A	Column B	Column C Additions		Column D	Column E
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
Valuation and qualifying accounts deducted from assets:					
2001:					
Allowance for uncollectible accounts (2)	$ 52	$ 24	$ —	$ 28(1)	$ 48
Provision for loss on generation-related regulatory assets and undercollected purchased power costs (3)	$ 6,939	$ —	$ —	$ 6,939	$ —
2000:					
Allowance for uncollectible accounts (2)	$ 46	$ 19	$ 2	$ 15(1)	$ 52
Provision for loss on generation-related regulatory assets and undercollected purchased power costs (3)	$ —	$ 6,939	$ —	$ —	$ 6,939
1999:					
Allowance for uncollectible accounts (2)	$ 47	$ 17	$ —	$ 18(1)	$ 46

(1) Deductions consist principally of write-offs, net of collections of receivables previously written off.

(2) Allowance for uncollectible accounts are deducted from “Accounts receivable Customers, net.”

(3) Provision was deducted from “Regulatory Assets.”

EXHIBIT INDEX

3.1 Restated Articles of Incorporation of PG&E Corporation effective as of May 5, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (File No. 1-12609), Exhibit 3.1)

3.2 Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2)

3.3 Bylaws of PG&E Corporation amended as of February 21, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.3)

3.4 Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of May 6, 1998 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-2348), Exhibit 3.1)

3.5 Bylaws of Pacific Gas and Electric Company amended as of February 21, 2001 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-2348), Exhibit 3.5)

4.1 First and Refunding Mortgage of Pacific Gas and Electric Company dated December 1, 1920, and supplements thereto dated April 23, 1925, October 1, 1931, March 1, 1941, September 1, 1947, May 15, 1950, May 1, 1954, May 21, 1958, November 1, 1964, July 1, 1965, July 1, 1969, January 1, 1975, June 1, 1979, August 1, 1983, and December 1, 1988 (incorporated by reference to Registration No. 2-1324, Exhibits B-1, B-2, and B-3; Registration No. 2-4676, Exhibit B-22; Registration No. 2-7203, Exhibit B-23; Registration No. 2-8475, Exhibit B-24; Registration No. 2-10874, Exhibit 4B; Registration No. 2-14144, Exhibit 4B; Registration No. 2-22910, Exhibit 2B; Registration No. 2-23759, Exhibit 2B; Registration No. 2-35106, Exhibit 2B; Registration No. 2-54302, Exhibit 2C; Registration No. 2-64313, Exhibit 2C; Registration No. 2-86849, Exhibit 4.3; and Pacific Gas and Electric Company's Form 8-K dated January 18, 1989 (File No. 1-2348), Exhibit 4.2)

In accordance with Item 601(b)(4)(iii) of Regulation S-K, each of PG&E Corporation or Pacific Gas and Electric Company agrees to furnish to the Commission any instruments respecting long-term debt not required to be filed by application of such item.

4.2 Form of Rights Agreement dated as of December 22, 2000, between PG&E Corporation and Mellon Investor Services LLC, including the Form of Rights Certificate as Exhibit A, the Summary of Rights to Purchase Preferred Stock as Exhibit B, and the Form of Certificate of Determination of Preferences for the Preferred Stock as Exhibit C (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 4.2)

10 The Gas Accord Settlement Agreement, together with accompanying tables, adopted by the California Public Utilities Commission on August 1, 1997, in Decision 97-08-055 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 1997 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2), as amended by Operational Flow Order (OFO) Settlement Agreement, approved by the California Public Utilities Commission on February 17, 2000, in Decision 00-02-050, as amended by Comprehensive Gas OII Settlement Agreement, approved by the California Public Utilities Commission on May 18, 2000, in Decision 00-05-049 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10)

10.1 Credit Agreement between PG&E Corporation, General Electric Capital Corporation, and Lehman Commercial Paper, Inc. dated March 1, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.2)

10.2 First Amendment to Credit Agreement between PG&E Corporation, General Electric Capital Corporation, and Lehman Commercial Paper, Inc. dated November 19, 2001.

10.3 Amended and Restated Credit Agreement among PG&E National Energy Group, Inc. and Chase Manhattan Bank dated August 22, 2001.

*10.4 PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001.

*10.5 Description of Compensation Arrangement between PG&E Corporation and Thomas G. Boren (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.2)

*10.6 Description of Compensation Arrangement between PG&E Corporation and Peter Darbee (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.3)

*10.7 Letter regarding Compensation Arrangement between PG&E Corporation and Thomas B. King dated November 4, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.6)

*10.8 Letter regarding Compensation Arrangement between PG&E Corporation and Lyn E. Maddox dated April 25, 1997 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.7)

*10.9 Letter Regarding Relocation Arrangement Between PG&E Corporation and Thomas B. King dated March 16, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (File No. 1-12609), Exhibit 10)

*10.10 Description of Relocation Arrangement Between PG&E Corporation and Lyn E. Maddox (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.9)

*10.11 PG&E Corporation Senior Executive Officer Retention Program approved December 20, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10)

*10.11.1 Letter regarding retention award to Robert D. Glynn, Jr. dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.1)

*10.11.2 Letter regarding retention award to Gordon R. Smith dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.2)

*10.11.3 Letter regarding retention award to Peter A. Darbee dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.3)

*10.11.4 Letter regarding retention award to Bruce R. Worthington dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.4)

*10.11.5 Letter regarding retention award to G. Brent Stanley dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.5)

*10.11.6 Letter regarding retention award to Daniel D. Richard dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.6)

*10.11.7 Letter regarding retention award to James K Randolph dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.7)

*10.11.8 Letter regarding retention award to Gregory M. Rueger dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.8)

*10.11.9 Letter regarding retention award to Kent Harvey dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.9)

*10.11.10 Letter regarding retention award to Roger J. Peters dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.10))

*10.11.11 Letter regarding retention award to Thomas G. Boren dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.11)

*10.11.12 Letter regarding retention award to Lyn E. Maddox dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.12)

*10.11.13 Letter regarding retention award to P. Chrisman Iribe dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.13)

*10.11.14 Letter regarding retention award to Thomas B. King dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.14)

*10.12 Pacific Gas and Electric Company Management Retention Program (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609), Exhibit 10.1)

*10.13 PG&E Corporation Management Retention Program (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609), Exhibit 10.2)

*10.14 PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2)

*10.15 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.14)

*10.16 Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended as of September 19, 2001.

*10.17 Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1989 (File No. 1-2348), Exhibit 10.16)

*10.18 Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1991 (File No. 1-2348), Exhibit 10.16)

*10.19	PG&E Corporation Retirement Plan for Non-Employee Directors, as amended and terminated January 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1997 (File No. 1-12609), Exhibit 10.13)
*10.20	PG&E Corporation Long-Term Incentive Program, as amended May 16, 2001, including the PG&E Corporation Stock Option Plan, Performance Unit Plan, and Non- Employee Director Stock Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)
*10.21	PG&E Corporation Executive Stock Ownership Program, amended as of September 19, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.20)
*10.22	PG&E Corporation Officer Severance Policy, amended as of July 21, 1999 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.1)
*10.23	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
*10.24	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.2)
*10.25	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2002.
11	Computation of Earnings Per Common Share
12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
13	2001 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company—portions of the Report to Shareholders under the headings "Selected Financial Data," "Management's Discussion and Analysis," "Independent Auditors' Report," "Responsibility for Consolidated Financial Statements," financial statements of PG&E Corporation entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Common Stockholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," "Consolidated Statements of Stockholders' Equity," "Notes to Consolidated Financial Statements," and "Quarterly Consolidated Financial Data (Unaudited)" are included only
21	Subsidiaries of the Registrant
23	Independent Auditors' Consent (Deloitte & Touche LLP)
24.1	Resolutions of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company authorizing the execution of the Form 10-K
24.2	Powers of Attorney

* Management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

EXHIBIT 10.2

FIRST AMENDMENT TO CREDIT AGREEMENT

FIRST AMENDMENT, dated as of November 19, 2001 (this " *Amendment* "), to the Credit Agreement, dated as of March 1, 2001 (as amended, supplemented or otherwise modified from time to time, the " *Credit Agreement* "), among PG&E Corporation, a California corporation (the " *Borrower* "), the lenders party thereto (the " *Lenders* "), General Electric Capital Corporation, a New York corporation, as Co-Arranger (in such capacity, the " *Co-Arranger* "), Lehman Commercial Paper Inc., a New York corporation, as Administrative Agent (in such capacity, the " *Administrative Agent* "), and Lehman Brothers Inc., a Delaware corporation, as Lead Arranger and Book Manager (in such capacity, the " *Lead Arranger* ").

W I T N E S S E T H:

WHEREAS, the Borrower, the Lenders, the Co-Arranger, the Administrative Agent and the Lead Arranger are parties to the Credit Agreement;

WHEREAS, the Borrower has requested that the Administrative Agent and the Lenders amend certain provisions of the Credit Agreement; and

WHEREAS, the Administrative Agent, the Lenders and the other parties hereto are willing to agree to the requested amendments on the terms and conditions contained herein;

NOW THEREFORE, in consideration of the premises herein contained and for other good and valuable consideration, the receipt of which is hereby acknowledged, the parties hereto hereby agree as follows:

1. *Defined Terms* . Unless otherwise defined herein, capitalized terms used herein which are defined in the Credit Agreement are used herein as therein defined.

2. *Amendments to the Credit Agreement* . (a) Appendix A to the Credit Agreement is hereby amended by deleting therefrom the definitions of "Authorized Officer," "Disclosure Letter," "Extension Fee," "Financing Documents," "Tranche A Lender" and "Tranche B Lender" and by substituting, in lieu thereof, the following in their respective places:

" ' *Authorized Officer* ' shall mean (i) with respect to any Person that is a corporation or a limited liability company, the Chairman, President, any Vice President, Treasurer or Secretary of such Person and (ii) with respect to any Person that is a partnership, the President, any Vice President, Treasurer or Secretary (or Assistant Secretary) of a general partner or managing partner of such Person and in each case whose name appears on a certificate of incumbency of such Person delivered in accordance with the Credit Agreement, as such certificate may be amended from time to time."

" ' *Disclosure Letter* ' shall mean the letter from the Borrower, addressed to the Administrative Agent and the Lenders, dated as of March 2, 2001, with respect to certain disclosure of the Borrower, as amended, modified or

supplemented by the letter dated May 14, 2001 and the letter, captioned "Supplemental Disclosure Letter" dated the First Amendment Effective Date."

" ' *Extension Fee* ' shall have the meaning set forth in the Fee Letter, the Lehman Fee Letter or the Additional Fee Letter, as applicable."

" ' *Financing Documents* ' shall mean, collectively, the Credit Agreement, the Notes, the Fee Letter, the Lehman Fee Letter, the Additional Fee Letter, the Escrow Agreement, the Security Documents and the Option Agreement."

" ' *Tranche A Lender* ' shall be the collective reference to (i) General Electric Capital Corporation, a New York corporation, and (ii) any other holder of the Tranche A Loan (including, without limitation, any Lender which becomes a holder of the Tranche A Loan pursuant to Section 2.10)."

" ' *Tranche B Lender* ' shall be the collective reference to Lehman Commercial Paper Inc., a New York corporation, and any Assignee thereof pursuant to Section 9.11."

(b) Appendix A to the Credit Agreement is hereby amended by adding thereto each of the following new definitions in its proper alphabetical order:

" ' *Additional Extended Date Certain* ' shall mean each of (i) March 2, 2005, and (ii) March 2, 2006."

" ' *Attala Note* ' shall mean that certain Promissory Note dated September 28, 2000, executed by Attala Power Corporation, a Delaware corporation, in favor of the Borrower."

" ' *Additional Fee Letter* ' shall mean the fee letter, dated the First Amendment Effective Date, between the Borrower and the Administrative Agent."

" ' *Bring Down Disclosure Letter* ' shall mean the letter captioned "Bring Down Disclosure Letter" from the Borrower, addressed to the Administrative Agent and the Lenders, dated the First Amendment Effective Date."

" ' *Excess Additional Option Percentage* ' shall have the meaning provided in Section 2.10(c)."

" ' *Extension Interest Prepayment Amount* ' shall mean with respect to an extension of the maturity date granted pursuant to Section 2.9(b) of the Credit Agreement the amount that is the total amount of interest payable on the Loans during such extension period based on a one-year Eurodollar Rate as of the first date of such extension discounted to present value as of such date using a discount rate of 4.25%."

" ' *First Amendment Effective Date* ' shall mean the date on which the First Amendment, dated as of November 16, 2001, to this Agreement became effective in accordance with its terms, which date is November 19, 2001."

" ' *LLC* ' shall mean individually and collectively PG&E National Energy Group, LLC, a Delaware limited liability company and the New LLC.

" ' *NEG Equity Sale* ' shall mean the sale of up to 20% of the outstanding equity of NEG, Inc., substantially in the manner described in the NEG Equity Sale Letter with such changes in the transactions described therein as may hereafter occur; *provided* that no such changes will be made that will adversely affect the Lenders' security interest in the Collateral or the rights of the Holders under the Option Agreement (other than the effect of the release of up to 20% of the outstanding equity of NEG, Inc. to be released by the Lenders pursuant to the terms hereof in connection with any NEG Equity Sale)."

" ' *NEG Equity Sale Letter* ' shall mean the letter from the Borrower addressed to the Administrative Agent and the Lenders dated of even date herewith, describing the terms of a potential sale of no more than 20% of the outstanding equity of NEG, Inc. and certain other actions related thereto."

" ' *New Investor* ' shall mean any purchaser of shares of the outstanding equity of NEG, Inc. in connection with the NEG Equity Sale, and their successors and assigns."

" ' *New LLC* ' shall have the meaning provided in Section 7."

" ' *Supplemental Schedule* ' shall mean the "Supplemental Schedule" delivered by the Borrower to the Administrative Agent and the Lenders on the First Amendment Effective Date."

" ' *Utility Spin-Off* ' shall mean individually and collectively, any transfers, Investments, Indebtedness, Dividends, and other transactions to the extent substantially consistent with the transactions described in the attached Annex 1 and undertaken pursuant to a confirmed plan of reorganization of PGE Utility under Chapter 11 of the Bankruptcy Code."

(c) Section 2 of the Credit Agreement is hereby amended by adding the following new Section 2.10 at the end thereof:

"2.10 *Conversion of Tranche B Loan; Conversion of Put Option Purchase Price to Tranche A Loans* . (a) Notwithstanding anything in this Agreement or any other Financing Document to the contrary, on the First Amendment Effective Date, $92,000,000 of the outstanding principal amount of the Tranche B Loan shall be automatically converted into, and become part of, the Tranche A Loan with the identical terms of the existing Tranche A Loan and shall be held by the Tranche B Lender and any Assignee thereof on a ratable basis. For the avoidance of doubt, after giving effect to the conversion described above, the aggregate

principal amount of the Tranche A Loan and the Tranche B Loan outstanding on the First Amendment Effective Date shall be $692,000,000 and $308,000,000, respectively.

(b) In the event that, pursuant to Article VI of the Option Agreement, any Holder exercises its right to put any Option of such Holder to a Purchasing Party on any Put Repurchase Date (as defined in the Option Agreement) prior to the Additional Extended Date Certain, the Put Option Purchase Price (as defined in the Option Agreement) with respect to such put shall be determined in accordance with the Option Agreement, and, as provided in Section 6.04 of the Option Agreement, the amount of such Put Option Purchase Price shall be paid in immediately available funds or, at Borrower's option, shall be deemed to constitute a Tranche A Loan made by such Holder, or its Affiliate Lender, on such Put Repurchase Date in a principal amount equal to the amount of such Put Option Purchase Price.

(c) In the event that, pursuant to Section 2.01(b) of the Option Agreement, the Holders may be entitled to receive an Additional Option (as defined in the Option Agreement) to purchase from LLC in excess of one percent (1.0%) of the total common equity of NEG, Inc. computed on a Fully Diluted Basis (as defined in the Option Agreement) (such excess only, the "Excess Additional Option Percentage"), at Borrower's option, (i) LLC may grant such Additional Option with respect to the Excess Additional Option Percentage in accordance with the terms of Section 2.01(b) of the Option Agreement, or (ii) the amount of the Put Option Purchase Price (as defined in the Option Agreement) with respect to such Excess Additional Option Percentage shall be determined in accordance with Section 2.01(b) of the Option Agreement, and, as provided therein, the amount of such Put Option Purchase Price with respect to such Excess Additional Option Percentage (x) shall be paid in immediately available funds or, at Borrower's option, (y) shall be deemed to constitute a Tranche A Loan made by such Lender on such Put Repurchase Date in a principal amount equal to the amount of such Put Option Purchase Price with respect to such Excess Additional Option Percentage.

Any Tranche A Loan arising pursuant to Section 2.10(b) or (c) shall be subject to the terms and conditions of this Agreement applicable to the Tranche A Loan and shall be evidenced by a Note in a principal amount equal to the applicable Put Option Purchase Price, which Note the Borrower shall duly execute and deliver to such Lender on the applicable Put Repurchase Date."

(d) Section 2.9 of the Credit Agreement is hereby amended by deleting such Section in its entirety and by substituting, in lieu thereof, the following:

"2.9 *Extension of Maturity Date* . (a) The Borrower may by notice to the Administrative Agent and the holders of the Tranche A Loan not later than thirty (30) days prior to March 2, 2003 or September 2, 2003 (if the maturity date of the Tranche A Loan was extended March 2, 2003 to September 2, 2003), and upon

payment of the Extension Fees relating to such extension, extend the maturity date of the Tranche A Loan to the earlier of (i) the date of a Spin-Off of NEG, Inc. and (ii) September 2, 2003 or March 2, 2004, as set forth in the Borrower's notice, but in no event shall the Date Certain with respect to the Tranche A Loan be beyond March 2, 2004, unless further extended pursuant to Section 2.9(b) below; *provided* , that there shall be no extension of the maturity date of the Tranche A Loan pursuant to this Section 2.9(a) if on the date of such extension, (i) a Default or an Event of Default shall be continuing or (ii) the Tranche B Loan shall not have been paid in full.

(b) The Borrower may by notice to the Administrative Agent and the holders of the Tranche A Loan not later than thirty (30) days prior to March 2, 2004 or March 2, 2005 (if the maturity date of the Tranche A Loan was extended to March 2, 2005), and upon payment of the Extension Fees relating to such extension, extend the maturity date of the Tranche A Loan to the earlier of (i) the date of a Spin-Off of NEG, Inc. and (ii) March 2, 2005 or March 2, 2006, respectively, but in no event shall the Date Certain with respect to the Tranche A Loan be beyond March 2, 2006; *provided* , that there shall be no extension of the maturity date of the Tranche A Loan pursuant to this paragraph (b) if (i) on the date of such extension, a Default or an Event of Default shall be continuing, (ii) the Tranche B Loan shall not have been paid in full on or before the earlier of (x) March 3, 2002 and (y) the date which is twenty (20) days after the Borrower or any of its Subsidiaries receives cash payment in full of the Attala Note, in an amount equal to 100% of such cash payments or (iii) on the date of such extension the Borrower (x) does not own cash or Cash Equivalents in its name in an amount no less than 15% of the total principal amount of Loans then outstanding, free and clear of all Liens and (y) has not prepaid the Extension Interest Prepayment Amount.

(c) Any extension of the maturity date of the Tranche A Loan made pursuant to this Section 2.9 shall become effective on the maturity date in effect immediately prior to giving effect to such extension."

(e) Section 3.2(b) of the Credit Agreement is hereby amended by deleting such Section in its entirety and by substituting, in lieu thereof, the following:

"(b) (i) In addition to any other mandatory repayments pursuant to this Section 3.2, on the date which is 20 days after the Borrower or any of its Subsidiaries receives any cash payments made pursuant to the Atalla Note, an amount equal to 100% of such cash payments shall be applied on such date in accordance with the requirements of Section 3.2(h).

(ii) In addition to any other mandatory repayments pursuant to this Section 3.2, on each date on or after the Closing Date upon which LLC, NEG, Inc. or any NEG Subsidiary receives any cash proceeds from any incurrence by LLC, NEG, Inc. or any NEG Subsidiary of Indebtedness for borrowed money, an amount equal to 100% of the Net Debt Proceeds of the respective incurrence of

Indebtedness shall be applied on such date in accordance with the requirements of Section 3.2(h); *provided* that such Net Debt Proceeds shall not be required to be so applied to the extent such Net Debt Proceeds are (x) retained as cash or Cash Equivalents by LLC, NEG, Inc. or any NEG Subsidiary or (y) applied to repay Indebtedness for borrowed money of NEG, Inc. or any NEG Subsidiary or (iii) reinvested in the business of NEG, Inc. or any NEG Subsidiary within the scope of business as described by the Business Plan; *provided* , *further* , that if a Default or Event of Default shall have occurred and be continuing, such reinvestment may only be made to the extent specified in Part II of the Business Plan."

(f) Section 3.2(h) of the Credit Agreement is hereby amended by deleting such Section in its entirety and by substituting, in lieu thereof, the following:

"(h) Each amount (other than any amount described in Section 3.2(b)(A)) required to be applied pursuant to this Section 3.2(h) shall be first paid to the Lenders ratably according to the respective outstanding principal amounts of Loans held by the Lenders and shall be applied by each Lender to payment of any amount owing to such Lender under Section 2.8, then to payment of any interest then due and payable to such Lender, and then to reduce ratably the remaining principal balance of the Loans of such Lender. Each amount described in Section 3.2(b)(i) required to be applied pursuant to this Section 3.2(h) shall be first paid to the Tranche B Lenders ratably according to the respective outstanding principal amounts of the Tranche B Loan held by such Tranche B Lenders and shall be applied by each such Tranche B Lender to payment of any amount owing to such Tranche B Lender under Section 2.8, then to payment of any interest then due and payable to such Tranche B Lender on account of the Tranche B Loan, and then to reduce the remaining principal balance of the Tranche B Loan of such Tranche B Lender; and after payment in full of the amounts described above in this sentence, any funds remaining from the amount described in Section 3.2(b)(A) shall be applied as specified in the first sentence of this paragraph."

(g) Section 5.16(c) is hereby amended by deleting such clause (c) in its entirety and substituting, in lieu thereof, the following:

"(c) Each member of the NEG Group (other than a QF during the period during which it was a QF) that owns assets subject to the jurisdiction of FERC pursuant to the FPA or sells power at wholesale in the United States has charged rates or provided services only pursuant to either: (i) one or more rate schedules on file with FERC; or (ii) market rate contracts in compliance with such entity's market rate authority from FERC, in each case, except such noncompliances with ongoing ministerial FERC filing requirements previously disclosed in writing to Lenders and other noncompliances which, in each case, could not reasonably be expected to affect the status of any member(s) of the NEG Group as an EWG or power marketer or have a Material Adverse Effect or result in a Material Adverse Change to NEG, Inc. or any of the NEG Subsidiaries. Each QF during the period it was a QF has sold power only in a manner consistent with its status as a QF."

(h) Section 6.1(a) of the Credit Agreement is hereby amended by deleting the number "45" in line one thereof and substituting the number "60" therefor, and deleting the phrase "and consolidating" in lines three and seven thereof.

(i) Section 6.1(b) of the Credit Agreement is hereby amended by deleting the number "90" in line one thereof and substituting the number "120" therefor.

(j) Section 6.18 of the Credit Agreement is hereby amended by deleting such Section in its entirety and by substituting, in lieu thereof, the following:

"6.18 *Cash Reserve* . (a) The Borrower shall at all times commencing on March 2, 2002 and until and including the earlier of (i) repayment in full of the Loans and (ii) (x) March 2, 2003 or (y) if such date is extended, March 2, 2004, own cash or Cash Equivalents in its name in an amount no less than 15% of the total principal amount of Loans then outstanding, free and clear of all Liens.

(b) The Borrower shall at all times after the extension of the Date Certain pursuant to Section 2.9(b) and until the Loans are repaid in full own cash or Cash Equivalents in its name in an amount no less than 10% of the total principal amount of Loans then outstanding, free and clear of all Liens; *provided* , that if at any time after any such extension pursuant to Section 2.9(b) the Borrower shall fail to comply with the requirements of this Section 6.18(b), the Borrower shall be permitted to cure such noncompliance by prepaying the Extension Interest Prepayment Amount."

(k) Section 7 of the Credit Agreement is hereby amended to add the following new Section at the end thereof:

"7.12 Nothing in this Section 7 shall prohibit (a) the effectuation of the Utility Spin-Off, (b) the transfer of up to 200 shares of the common stock of NEG, Inc. to a wholly-owned Subsidiary of NEG, Inc. (the "New LLC"), *provided* that prior to such transfer, the New LLC becomes a party to the Stock Pledge Agreement on the same terms as those applicable to the Borrower, or (c) the NEG Equity Sale."

(l) Section 7.1 of the Credit Agreement is hereby amended by deleting the word "and" after the end of clause (xii) thereof, deleting the period after the end of clause (xiii) thereof and substituting therefor the phrase "; and", and adding the following new clause (xiv) thereto:

"(xiv) Liens on assets of the Borrower to secure Hedging Agreements entered into in the ordinary course of business by the Borrower hedging the interest rate fluctuations in respect of interest payable on the Loan."

(m) Section 7.1 (viii) of the Credit Agreement is hereby amended by deleting the proviso at the end thereof in its entirety and by substituting, in lieu thereof, the following:

" *provided* that the aggregate amount of deposits at any time pursuant to sub-clauses (y) and (z) and other Indebtedness permitted under Section 7.4(ix) shall not exceed $25,000,000 in the aggregate."

(n) Section 7.3 of the Credit Agreement is hereby amended by deleting such Section in its entirety and by substituting, in lieu thereof, the following:

"7.3 *Dividends* . The Borrower will not, and will not permit any of the other Covered Parties to, authorize, declare or pay any Dividends (other than the Dividend being Refinanced hereunder), except that (i) any Subsidiary of the Borrower may pay cash Dividends to the Borrower or to LLC, NEG, Inc. or any NEG Subsidiary, (ii) NEG, Inc. may distribute a note to LLC or the Borrower, and LLC may distribute any such note to the Borrower, solely in connection with the IPO, (iii) LLC may authorize, declare and pay Dividends to the Borrower in connection with a Spin-Off of NEG, Inc. and (iv) NEG, Inc. may pay cash Dividends to any New Investor to the extent that Dividends are paid pro rata to the Borrower and such New Investor in accordance with their respective equity interests in NEG, Inc.

Nothing in this Section shall prohibit the Borrower or LLC from performing in full its obligations under Article VI of the Option Agreement."

(o) Section 7.4 of the Credit Agreement is hereby amended by deleting the word "and" after the end of clause (vi) thereof, deleting the period after the end of clause (vii) thereof and substituting therefor a comma, and adding the following new clauses (viii) and (ix) thereto:

"(viii) Hedging Agreements entered into in the ordinary course of business by the Borrower hedging the interest rate fluctuations in respect of interest payable on the Loan; and

(ix) other Indebtedness, *provided* that the aggregate amount of such other Indebtedness together with deposits permitted under sub-clauses (y) and (z) of Section 7.1(viii) shall not exceed the amount set forth in Section 7.1(viii)."

(p) Section 7.5 of the Credit Agreement is hereby amended by deleting the word "and" after the end of clause (x) thereof, deleting the period after the end of clause (xi) thereof and substituting therefor the phrase "; and", and adding the following new clause (xii) thereto:

"(xi) any Investment in a Hedging Agreement entered into by the Borrower hedging the interest rate fluctuations in respect of interest payable on the Loan."

(q) Section 9 of the Credit Agreement is hereby amended to add the following new Section 9.24:

"9.24 *Release of Liens for NEG Equity Sale* . Concurrently with the consummation of the NEG Equity Sale, the Lenders agree to cause the Collateral Agent (at the expense of the Borrower) to release the security interest held by the Collateral Agent, pursuant to the Stock Pledge Agreement, in the shares of common stock of NEG, Inc. being sold in the NEG Equity Sale."

(r) Effective as of the date hereof, anywhere the term "Chief Financial Officer" is used in the Credit Agreement with respect to any Person such term shall be understood to include the Treasurer of such Person.

(s) Effective as of the date hereof, all references to "Schedule" or "Schedules" in the Credit Agreement or any other Financing Document shall be deemed to be references to the Schedules attached hereto; *provided* , that references to "Schedule" or "Schedules" in representations or warranties made prior to the date hereof shall be references to the Schedules attached to the Credit Agreement prior to the effectiveness of this Amendment, as modified by the Supplemental Schedule.

3. *Effectiveness* . This Amendment shall become effective as of the date hereof when (i) each Lender shall have received counterparts hereof duly executed by the Borrower, the Co-Arranger, the Lead Arranger, the Administrative Agent and the Lenders, (ii) the Administrative Agent shall have received, for the account of each Lender that has executed this Amendment on or prior to 5:00 p.m. (New York time) on November 19, 2001, an amendment fee in an amount equal to 1.0% of the outstanding Tranche A Loan of such Lender on such date after giving effect to the amendment to Section 2.10 of the Credit Agreement set forth herein, which fee shall be payable to such Lender upon effectiveness of this Amendment, (iii) each Lender shall have received acknowledgments and consents hereto from the Borrower, LLC and NEG, Inc. under the LLC Pledge Agreement and the Stock Pledge Agreement, as applicable, (iv) each Lender shall have received copies of the First Amendment, dated the date hereof, to the Option Agreement, duly executed by each party thereto and consented to by each Person specified therein (the " *Option Amendment* ") and (v) each Lender shall have received favorable opinions of counsel to the Borrower, LLC and NEG, Inc. covering such matters with respect to this Agreement, the Option Amendment, the Additional Fee Letter and the transactions contemplated hereby as the Lenders shall reasonably request.

4. *Representations and Warranties* . The Borrower hereby represents and warrants that each of the representations and warranties of the Borrower and its Subsidiaries contained in the Credit Agreement and the other Financing Documents (as modified by the Bring Down Disclosure Letter and the Schedules attached hereto) shall be, after giving effect to this Amendment, true and correct in all material respects, as if made on and as of the date hereof except for any representations and warranties made as of a specific date, which shall be true and correct in all material respects as of such date; *provided* that with respect to Section 5.19 of the Credit Agreement the filing by PGE Utility of a petition with the United States Bankruptcy Court on April 6, 2001, shall be an exception to such representation and warranty that no Reportable Event has occurred.

5. *Reference to Credit Agreement* . Upon the effectiveness of this Amendment, each reference in the Credit Agreement to "this Agreement," "hereunder," or words of like or

similar import shall mean and be reference to the Credit Agreement as affected and amended by this Amendment.

6. *Continuing Effect of Credit Agreement* . This Amendment shall not be construed as a waiver or consent to any further or future action on the part of the Borrower or any of its Subsidiaries that would require a waiver or consent of the Administrative Agent and/or the Lenders. Except as amended hereby, the provisions of the Credit Agreement and the other Financing Documents are and shall remain in full force and effect.

7. *Counterparts* . This Amendment may be executed in counterparts and all of the said counterparts taken together shall be deemed to constitute one and the same instrument. This Amendment may be validly executed and delivered by facsimile or other electronic transmission.

8. ***GOVERNING LAW, ETC .*** **THIS AMENDMENT SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK.**

9. *Expenses* . The Borrower agrees to pay or reimburse the Administrative Agent and each Lender for all of its out-of-pocket costs and expenses incurred in connection with the preparation, negotiation and execution of this Amendment, including, without limitation, the fees and disbursements of counsel to the Administrative Agent and counsel to General Electric Capital Corporation, as a Lender.

[The remainder of this page is intentionally left blank.]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be executed and delivered by their duly authorized officers as of the date first written above.

PG&E CORPORATION

By: Peter A. Darbee

Name: Peter A. Darbee
Title: Senior Vice President and Chief Financial Officer

GENERAL ELECTRIC CAPITAL CORPORATION, as a Lender and Co-Arranger

By: J. Alex Urquhart, Jr.

Name: J. Alex Urquhart, Jr.
Title: Vice President of GECC

LEHMAN COMMERCIAL PAPER INC.,
as a Lender and Administrative Agent

By: Jeff Goodwin

Name: Jeff Goodwin
Title: Authorized Signatory

WILMINGTON TRUST COMPANY, as a Lender

By: Bruce L. Bisson

Name: Bruce L. Bisson
Title: Vice President

Each of the undersigned does hereby consent and agree to the foregoing Amendment and acknowledge and agree that (i) all obligations of the Borrower under the Credit Agreement, as amended by the foregoing Amendment, are Secured Obligations (as defined in the relevant Security Document) which are secured by the Security Documents to which it is a party, (ii) all references to the Credit Agreement in the Security Documents refer to the Credit Agreement, as amended from time to time (including pursuant to the foregoing Amendment), and (iii) all references to Loans in the Security Documents refer to the Loans under the Credit Agreement.

PG&E CORPORATION

By: Peter A. Darbee

Name: Peter A. Darbee
Title: Senior Vice President and Chief Financial Officer

PG&E NATIONAL ENERGY GROUP, LLC

By: Thomas G. Boren

Name: Thomas G. Boren
Title: President and Chief Executive Officer

PG&E NATIONAL ENERGY GROUP, INC.

By: Thomas G. Boren

Name: Thomas G. Boren
Title: President and Chief Executive Officer

EXHIBIT 10.3

$1,250,000,000

AMENDED AND RESTATED CREDIT AGREEMENT

among

PG&E NATIONAL ENERGY GROUP, INC.,
as Borrower

THE CHASE MANHATTAN BANK,
as Issuing Bank

The Several Lenders
from Time to Time Parties Hereto,

BARCLAYS BANK PLC and
WESTDEUTSCHE LANDESBANK GIROZENTALE, NEW YORK BRANCH,
as Documentation Agents

DRESDNER BANK AG, NEW YORK AND GRAND CAYMAN BRANCHES, and
THE ROYAL BANK OF SCOTLAND PLC,
as Syndication Agents

and

THE CHASE MANHATTAN BANK,
as Administrative Agent

J.P. MORGAN SECURITIES INC.,
as Lead Arranger and Bookrunner

Dated as of August 22, 2001

Table of Contents

		Page
ARTICLE I DEFINITIONS		1
SECTION 1.1	Defined Terms.	1
SECTION 1.2	Other Definitional Provisions.	21
ARTICLE II LETTERS OF CREDIT		22
SECTION 2.1	L/C Commitment.	22
SECTION 2.2	Procedure for Issuance of Letter of Credit.	23
SECTION 2.3	Fees and Other Charges.	23
SECTION 2.4	L/C Participations.	24
SECTION 2.5	Reimbursement Obligation of the Borrower	25
SECTION 2.6	Obligations Absolute	26
SECTION 2.7	Letter of Credit Payments	26
SECTION 2.8	Applications for Issuance	26
ARTICLE III LOANS		26
SECTION 3.1	Loans	26
SECTION 3.2	Procedure for Loan Borrowing	27
SECTION 3.3	Evidence of Debt.	28
SECTION 3.4	Facility Fees, etc	28
SECTION 3.5	Termination or Reduction of Commitments	28
SECTION 3.6	Optional Prepayments; Mandatory Prepayments	29
SECTION 3.7	Conversion and Continuation Options	29
SECTION 3.8	Limitations on Eurodollar Tranches	30
SECTION 3.9	Interest Rates and Payment Dates	30
SECTION 3.10	Computation of Interest and Fees	31
SECTION 3.11	Inability to Determine Interest Rate	31
SECTION 3.12	Pro Rata Treatment and Payments	31
SECTION 3.13	Requirements of Law	33
SECTION 3.14	Taxes	34
SECTION 3.15	Indemnity	35
SECTION 3.16	Illegality	36
SECTION 3.17	Change of Lending Office	36
SECTION 3.18	Replacement of Lenders	37
SECTION 3.19	Extension of Termination Dates	37
ARTICLE IV REPRESENTATIONS AND WARRANTIES		39
SECTION 4.1	Organization; Powers; Ownership of Property	39
SECTION 4.2	Authorization	40
SECTION 4.3	Enforceability	40
SECTION 4.4	Financial Statements	40
SECTION 4.5	Litigation	40
SECTION 4.6	Federal Reserve Regulations	40
SECTION 4.7	Investment Company Act; Public Utility Holding Company Act	41
SECTION 4.8	No Material Misstatements	41
SECTION 4.9	Taxes	41
SECTION 4.10	Employee Benefit Plans	42
SECTION 4.11	Governmental Approval; Compliance with Law and Contracts	42
SECTION 4.12	Environmental Matters	42
SECTION 4.13	Ranking	42
SECTION 4.14	Unrestricted Subsidiaries	43
SECTION 4.15	Use of Letters of Credit	43

Table of Contents

		Page
SECTION 4.16	CPUC	43
SECTION 4.17	Separateness from PG&E	43
ARTICLE V CONDITIONS PRECEDENT		43
SECTION 5.1	Conditions to Initial Extension of Credit	43
SECTION 5.2	Conditions to Issuance of Each Letter of Credit under Section 2.1 and each Loan under Section 3.1(a) and 3.1(b)	45
ARTICLE VI COVENANTS		45
SECTION 6.1	Maintenance of Ownership	45
SECTION 6.2	Existence	45
SECTION 6.3	Compliance with Law; Business and Properties	46
SECTION 6.4	Financial Statements, Reports, Etc	46
SECTION 6.5	Insurance	47
SECTION 6.6	Taxes, Etc	48
SECTION 6.7	Maintaining Records; Access to Properties and Inspections	48
SECTION 6.8	Risk Management Procedures	48
SECTION 6.9	Merger	48
SECTION 6.10	Investments	48
SECTION 6.11	Liens	49
SECTION 6.12	Indebtedness	50
SECTION 6.13	Transactions with Affiliates	52
SECTION 6.14	Distributions	52
SECTION 6.15	Financial Covenants	53
SECTION 6.16	Separateness from PG&E Corp	53
SECTION 6.17	Asset Sales	53
ARTICLE VII EVENTS OF DEFAULT		53
SECTION 7.1	Events of Default	53
ARTICLE VIII THE AGENTS		57
SECTION 8.1	Appointment	57
SECTION 8.2	Delegation of Duties	57
SECTION 8.3	Exculpatory Provisions	57
SECTION 8.4	Reliance by Administrative Agent	57
SECTION 8.5	Notice of Default	58
SECTION 8.6	Non-Reliance on Administrative Agent and Other Lenders	58
SECTION 8.7	Indemnification	59
SECTION 8.8	Agent in Its Individual Capacity	59
SECTION 8.9	Successor Administrative Agent	59
SECTION 8.10	Documentation and Syndication Agents	60
ARTICLE IX MISCELLANEOUS		60
SECTION 9.1	Amendments and Waivers	60
SECTION 9.2	Notices	61
SECTION 9.3	No Waiver; Cumulative Remedies	62
SECTION 9.4	Survival of Representations and Warranties	62
SECTION 9.5	Payment of Expenses	62
SECTION 9.6	Successors and Assigns; Participations and Assignments	63
SECTION 9.7	Adjustments; Set-off	66
SECTION 9.8	Counterparts	67
SECTION 9.9	Severability	67
SECTION 9.10	Integration	67

Table of Contents

		Page
SECTION 9.11	GOVERNING LAW	67
SECTION 9.12	Submission To Jurisdiction; Waivers	67
SECTION 9.13	Acknowledgments	68
SECTION 9.14	Confidentiality	68
SECTION 9.15	Accounting Changes	69
SECTION 9.16	Delivery of Lender Addenda	69
SECTION 9.17	WAIVERS OF JURY TRIAL	69

SCHEDULES:

1.1	Commitments
1.1A	Applicable Margins
1.1B	Notices to Lenders
2.1	Existing Letters of Credit
2.3(B)	Letter of Credit Customary Fees and Costs
4.5	Litigation
4.12	Environmental Matters
4.14	Unrestricted Subsidiaries
6.1	Certain Restricted Subsidiaries
6.10	Investments
6.11	Other Liens
6.12(A)	Other Credit Facilities
6.12(F)	Existing Indebtedness
6.12(H)-1	Terms of Subordination - Affiliates
6.12(H)-2	Terms of Subordination - Non-Affiliates
6.12(J)	Permitted Sale-leaseback Transactions
6.13	Service Agreements

EXHIBITS:

A	Form of Closing Certificate
B	Form of Assignment and Acceptance
C-1	Form of Legal Opinion of Hunton & Williams
C-2	Form of Opinion of Hunton & Williams
C-3	Form of Legal Opinion of Stephen A. Herman
D	Form of Exemption Certificate
E	Form of Application for Issuance

among PG&E NATIONAL ENERGY GROUP, INC., a Delaware corporation (the "Borrower"), the several banks and other financial institutions from time to time parties to this Agreement (the "Lenders"), THE CHASE MANHATTAN BANK, as the letter of credit issuing bank (in such capacity, the "Issuing Bank"), BARCLAYS BANK PLC and WESTDEUTSCHE LANDESBANK GIROZENTALE, NEW YORK BRANCH, each as a documentation agent (in such capacity, collectively the "Documentation Agents"), DRESDNER BANK AG, NEW YORK AND GRAND CAYMAN BRANCHES and THE ROYAL BANK OF SCOTLAND PLC, each as a syndication agent (in such capacity, collectively the "Syndication Agents"), and THE CHASE MANHATTAN BANK, as Administrative Agent (in such capacity, the "Administrative Agent").

W I T N E S S E T H :

WHEREAS, some of the Lenders herein made available to the Borrower a 364-day revolving loan and letter of credit facility with a total committed amount of $550 million (the "$550M Credit Facility");

WHEREAS, the commitments to be made available under this Agreement will replace the $550M Credit Facility and will consist of a two-tranche revolving loan and letter of credit facility with a total committed amount of $1.25 billion as of the Closing Date; and

WHEREAS, the Issuing Bank and the Lenders are willing to make such credit facility available to the Borrower upon and subject to the terms and conditions set forth herein.

NOW, THEREFORE, in consideration of the premises and the agreements hereinafter set forth, the parties hereto hereby agree as follows:

ARTICLE I

DEFINITIONS

SECTION 1.1 Defined Terms.

As used in this Agreement, the terms listed in this Section 1.1 shall have the respective meanings set forth in this Section 1.1.

"$1.1 Billion PG&E Gen Credit Agreement" means the $1,100,000,000 Credit Agreement, dated as of September 1, 1998, among PG&E Gen and the lenders party thereto, as the same may be amended, modified or supplemented from time to time.

"$550M Credit Facility" has the meaning given such term in the first recital.

"Actual Knowledge" means, with respect to any Person as to any event or circumstance, the actual knowledge of the Responsible Officer of such Person or receipt by such Person from the Administrative Agent of notice of such event or circumstance.

"Administrative Agent" has the meaning given such term in the preamble hereto.

"Affiliate" means, when used with respect to a specified Person, another Person that directly or indirectly controls or is controlled by or is under common control with the Person specified. For this purpose, "control" of a Person shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person, whether through ownership of voting shares, by contract or otherwise.

"Agents" means the Administrative Agent, the Documentation Agents and the Syndication Agents.

"Aggregate Exposure" means with respect to any Lender at any time, an amount equal to the amount of such Lender's Commitment at such time or, if the Commitments have been terminated, the amount of such Lender's Extensions of Credit then outstanding.

"Aggregate Exposure Percentage" means with respect to any Lender at any time, the ratio (expressed as a percentage) of such Lender's Aggregate Exposure at such time to the sum of the Aggregate Exposures of all Lenders at such time.

"Agreement" means this Credit Agreement, as amended, supplemented or otherwise modified from time to time.

"Applicable Margin" means for Base Rate Loans and for Eurodollar Loans, as set forth in the Pricing Grid.

"Application for Issuance" means an application, in the form of Exhibit E, requesting the Issuing Bank to open a Letter of Credit.

"Arrangers" means J.P. Morgan Securities Inc., Salomon Smith Barney Inc.and Societe Generale, collectively.

"Asset Company" means any entity (a) (i) whose principal purpose is the acquisition, improvement, installation, design, engineering, construction, development, completion, financing, maintenance or operation of all or any part of a project or projects, or any asset related thereto, used in the business of generating, transmitting, transporting, distributing, producing or storing electric power, thermal energy, natural gas or other fuel or other energy-related businesses and (ii) substantially all its assets are limited to those assets being financed (or to be financed), or the operation of which is being financed (or to be financed), in whole or in part by a Project Financing Facility entered into by such entity and/or any Investment Vehicle that owns such entity or by contributions or intercompany loans from the Borrower, any Restricted Subsidiary or any such Investment Vehicle or (b) which entity is a Subsidiary of an entity described in clause (a) and the business and assets of which are related to the business of such entity and which does not incur any Indebtedness other than (A) intercompany loans from an Asset Company which is the parent of such Subsidiary, the Borrower, any Restricted Subsidiary or any Investment Vehicle that indirectly owns such Subsidiary, (B) Indebtedness of the type described in Section 6.12(i) or (C) Indebtedness under a Project Financing Facility.

"Assignee" has the meaning given such term in Section 9.6(c).

"Assignor" has the meaning given such term in Section 9.6(c).

"Available Commitment" means with respect to any Lender at any time, an amount equal to the excess, if any, of (a) such Lender's Commitment then in effect over (b) such Lender's Extensions of Credit.

"Base Rate" means for any day, a rate per annum (rounded upwards, if necessary, to the next 1/16 of 1%) equal to the greater of (a) the Prime Rate in effect on such day and (b) the Federal Funds Effective Rate in effect on such day plus 1/2 of 1%. Any change in the Base Rate due to a change in the Prime Rate or the Federal Funds Effective Rate shall be effective as of the opening of business on the effective day of such change in the Prime Rate or the Federal Funds Effective Rate, respectively.

"Base Rate Loans" means Loans for which the applicable rate of interest is based upon the Base Rate.

"Benefited Lender" has the meaning given such term in Section 9.7.

"Board" means the Board of Governors of the Federal Reserve System (or any successor).

"Borrower" has the meaning given such term in the preamble hereto.

"Borrowing Date" means any Business Day specified by the Borrower as a date on which the Borrower requests the Lenders to make Loans hereunder.

"Business Day" means (a) for all purposes other than as covered by clause (b) below, a day other than a Saturday, Sunday or other day on which commercial banks in New York City are authorized or required by law to close and
(b) with respect to all notices and determinations in connection with, and payments of principal and interest on, Eurodollar Loans, any day which is a Business Day described in clause (a) and which is also a day for trading by and between banks in Dollar deposits in the interbank eurodollar market.

"Cash Collateral Account" has the meaning given such term in Section 7.1.

"Cash Equivalents" means (a) any evidence of indebtedness with a maturity of 180 days or less issued or directly and fully guaranteed or insured by the United States, Canada or any U.S. agency or instrumentality; (b) certificates of deposit or acceptances or Eurodollar time deposits with a maturity of 180 days or less of, and overnight bank deposits and demand accounts with (i) any financial institution that is not a foreign bank or a foreign bank holding company that has a bankwatch rating of at least B/C by Fitch and a commercial paper rating of at least A-1 by S&P, F1 by Fitch or P-1 by Moody's or
(ii) any financial institution that is a foreign bank or a foreign bank holding company that has a sovereign risk rating of at least AA by Fitch, a bankwatch rating of at least B by Fitch, a commercial paper rating of at least A-1 by S&P, F1 by Fitch or P-1 by Moody's and a minimum of US$20 billion in assets; (c) commercial paper with a maturity of 180 days or less issued by a U.S. or Canadian incorporated company that is not an Affiliate of the Borrower and rated at least A-1 by S&P, F1 by Fitch or at least P-1 by Moody's; (d) Repurchase Agreements with a maturity of 90 days or less made with banks which meet the criteria in clause (b) above and primary government security dealers (as defined by the Federal Reserve System) which meet the criteria in clause (c) above, and are fully collateralized

by investments meeting the criteria of clause (a) above; (e) tax-exempt municipal obligations of any state of the United States, or any municipality of any such state which mature within 180 days from the date of acquisition thereof and which, in each case, are rated at least MIG-1 or VMIG-1 by Moody's, and SP-1/A-1 or AA/A-1 by S&P;and (f) institutional money market funds that exclusively invest in any of the foregoing.

"Cash Flow Available for Fixed Charges" for any period means, without duplication, (i) EBITDA of the Borrower and its Consolidated Subsidiaries which are not Unrestricted Subsidiaries for such period, minus (ii) EBITDA for such period of such Consolidated Subsidiaries that are financed with Indebtedness of such Subsidiary or which are direct or indirect Subsidiaries of a Financed Subsidiary of the Borrower, plus (iii) Distributions received by the Borrower from Subsidiaries described in the foregoing clause (ii) during such period except to the extent the amount of such Distributions previously constituted "Cash Flow Available for Fixed Charges" during such period as a result of clause (viii) below, minus (iv) Distributions described in the foregoing clause (iii) that are attributable to extraordinary gains or other non-recurring items described in clause (iii) of the definition of "EBITDA", minus (v) any income reported by the Borrower for such period for Persons that are not Consolidated Subsidiaries of the Borrower, plus (vi) Distributions received by the Borrower from Persons described in the foregoing clause (v) during such period, minus
(vii) Distributions described in the foregoing clause (vi) that are attributable to extraordinary gains or other non-recurring items described in clause (iii) of the definition of "EBITDA", plus, (viii) cash and Cash Equivalents of Subsidiaries described in clause (ii) above that are legally and contractually available to such Subsidiary for the payment of dividends to the Borrower, but only to the extent that the source of such cash and Cash Equivalents is from such Subsidiary's EBITDA for such period or from repayments during such period to such Subsidiary of loans made by such Subsidiary.

"Closing Date" means the date on which the conditions precedent set forth in Section 5.1 shall have been satisfied, which date is August 23, 2001.

"Code" means the Internal Revenue Code of 1986, as amended from time to time.

"Commitments" means, as to any Lender, the Tranche A Commitment and the Tranche B Commitment of such Lender.

"Conduit Lender" means any special purpose corporation organized and administered by any Lender for the purpose of making Loans otherwise required to be made by such Lender and designated by such Lender in a written instrument; provided, that the designation by any Lender of a Conduit Lender shall not relieve the designating Lender of any of its obligations to fund a Loan under this Agreement if, for any reason, its Conduit Lender fails to fund any such Loan, and the designating Lender (and not the Conduit Lender) shall have the sole right and responsibility to deliver all consents and waivers required or requested under this Agreement with respect to its Conduit Lender, and provided, further, that no Conduit Lender shall (a) be entitled to receive any greater amount pursuant to Section 3.13, 3.14, 3.15 or 9.5 than the designating Lender would have been entitled to receive in respect of the extensions of credit made by such Conduit Lender or (b) be deemed to have any Commitment.

"Consolidated Net Worth" means, as of any date of determination thereof, the amount which would be reflected as stockholders' equity upon a consolidated balance sheet of the Borrower (but excluding any portion thereof attributable to Unrestricted Subsidiaries) determined in accordance with GAAP, excluding other comprehensive income arising from the accounting treatment of hedging and mark-to-market transactions.

"Consolidated Subsidiary" means with respect to any Person at any date any Subsidiary or other entity the accounts of which would be consolidated in accordance with GAAP with those of such Person in its consolidated financial statements as of such date.

"Consolidated Tangible Net Assets" means at any date the total net assets of the Borrower and its Consolidated Subsidiaries (other than Unrestricted Subsidiaries) determined in accordance with GAAP, excluding, however, from the determination of total net assets (i) goodwill, organizational expenses, research and product development expenses, trade marks, trade names, copyrights, patents, patent applications, licenses and rights in any thereof, and other similar intangibles, (ii) all deferred charges or unamortized debt discount and expenses, (iii) all reserves carried and not deducted from assets,
(iv) securities which are not readily marketable, (v) cash held in sinking or other analogous funds established for the purpose of redemption, retirement or prepayment of capital stock or other equity interests or Indebtedness, and (vi) any items not included in clauses (i) through (v) above which are treated as intangibles in conformity with GAAP.

"Credit Agreement" means the Amended and Restated Credit Agreement, dated as of August 22, 2001, among the Borrower, the Lenders, the Issuing Bank, the Documentation Agents, the Syndication Agents and the Administrative Agent.

"Credit Support Arrangements" means any Guaranty, letter of credit or other instrument or arrangement issued as support for the payment or performance obligations of a party under any Trading Arrangement.

"Default" means any of the events specified in Section 7.1, which with the giving of notice, the lapse of time, or both, will become an Event of Default.

"Distribution" means, in respect of any Person, (i) any payment of any dividends or other distributions with respect to the capital stock or other equity interests of such Person (except distributions in such capital stock or other equity interests) and (ii) any purchase, redemption or other acquisition or retirement for value of any capital stock or other equity interests of such Person or any Affiliate of such Person unless made contemporaneously from the net proceeds of the sale of capital stock or other equity interests.

"Documentation Agents" has the meaning given such term in the preamble hereto.

"Dollars" and "$" means lawful currency of the United States of America.

"Downgrade Event" means (i) the Borrower's senior unsecured long term debt (x) ceases to be rated at least BBB- by S&P and (y) ceases to be rated at least Baa3 by Moody's (or if ratings of such debt have not been issued by such rating agencies, such debt ceases to be

impliedly rated by an issuer rating or indicative rating at least BBB- by S&P and Baa3 by Moody's).

"EBITDA" means, with respect to any Person for any period, the (i) income (or loss) before interest and taxes of such Person, plus (ii) to the extent deducted in determining such income (or loss), depreciation, amortization and other similar non-cash charges and reserves, minus (iii) to the extent recognized in determining such income (or loss), extraordinary gains (or losses), restructuring charges or other non-recurring items, plus (iv) to the extent deducted in determining such income (or loss), Lease Payment Obligations described in clause (iii) of the definition of "Lease Payment Obligations".

"Equity Funding Arrangement" means (i) an agreement to provide a capital contribution to or other equity investment in any Asset Company or Investment Vehicle in connection with any Project Financing Facility, (ii) a Guaranty, letter of credit or other similar arrangement with respect to any obligations of any Asset Company or Investment Vehicle under a Project Financing Facility, (iii) a Guaranty of any Investment Vehicle's obligation to make a capital contribution to or other equity investment in any Asset Company or Investment Vehicle in connection with a Project Financing Facility or (iv) a Guaranty, letter of credit or other similar arrangement to support any of the obligations or arrangements described in clauses (i) through (iii) hereof.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time.

"ERISA Affiliate" means any trade or business (whether or not incorporated) that is a member of a group of (i) organizations described in Sections 414(b) or 414(c) of the Code and (ii) solely for purposes of the Lien created under Section 412(n) of the Code, organizations described in Sections 414(m) or 414(o) of the Code of which the Borrower is a member.

"ERISA Event" means (i) the Borrower or any ERISA Affiliate shall fail to pay when due an amount or amounts aggregating in excess of $15,000,000 which it shall have become liable to pay under Title IV of ERISA; or (ii) notice of intent to terminate a Material Plan shall be filed under Title IV of ERISA by the Borrower or any ERISA Affiliate, any plan administrator or any combination of the foregoing; or (iii) the PBGC shall institute proceedings under Title IV of ERISA to terminate, to impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or to cause a trustee to be appointed to administer any Material Plan; or (iv) a condition shall exist by reason of which the PBGC would be entitled to obtain a decree adjudicating that any Material Plan must be terminated; or (v) there shall occur a complete or partial withdrawal from, or a default, within the meaning of Section 4219(c)(5) of ERISA, with respect to, one or more Multiemployer Plans which could cause the Borrower or any ERISA Affiliate to incur a current payment obligation in excess of $15,000,000; or (vi) receipt by the Borrower or any ERISA Affiliate of notice from one or more Multiemployer Plans of intent to terminate or that it is insolvent or in reorganization (within the meaning of Section 4241 or 4245 of ERISA, as applicable) which termination, insolvency or reorganization, individually or together with other such events, could cause the Borrower and/or any ERISA Affiliate, individually or in the aggregate, to incur a current payment obligation in excess of $15,000,000; or (vii) the Borrower or any ERISA Affiliate shall engage in one or more non-

exempt "prohibited transactions" (as defined in Section 406 of ERISA or Section 4975 of the Code) which could result in a current payment obligation of the Borrower and/or any ERISA Affiliate individually or in the aggregate, in an amount or amounts aggregating in excess of $15,000,000; or (viii) the occurrence of any event or series of events of which the nature described in clauses (i) through (vii) with respect to any Plan or Multiemployer Plan which, individually or in the aggregate, could result in a liability to the Borrower and/or any ERISA Affiliate, individually or in the aggregate, in an amount or amounts aggregating in excess of $50,000,000.

"ET Credit Agreements" means (i) the $50,000,000 Credit Agreement, dated as of November 13, 1998, between PG&E Energy Trading Gas Corporation, PG&E Energy Trading, Canada Corporation, ET Holdings, PG&E Energy Trading Power, L.P. and Bank of Montreal and (ii) the $35,000,000 Credit Agreement, dated as of November 13, 1998, between PG&E Energy Trading -- Gas Corporation, PG&E Energy Trading, Canada Corporation, PG&E Energy -- Trading Power Holdings Corporation, PG&E Energy Trading Power, L.P. and The Chase Manhattan Bank, as each may be amended, modified or supplemented from time to time.

"ET Holdings" means PG&E Energy Trading Holdings Corporation, a California corporation.

"Eurocurrency Reserve Requirements" means for any day, the aggregate (without duplication) of the maximum rates (expressed as a decimal fraction) of reserve requirements in effect on such day (including, without limitation, basic, supplemental, marginal and emergency reserves) under any regulations of the Board or other Governmental Authority having jurisdiction with respect thereto dealing with reserve requirements prescribed for eurocurrency funding (currently referred to as "Eurocurrency Liabilities" in Regulation D of the Board) maintained by a member bank of the Federal Reserve System.

"Eurodollar Base Rate" means with respect to each day during each Interest Period, the rate per annum determined on the basis of the rate for deposits in Dollars for a period equal to such Interest Period commencing on the first day of such Interest Period appearing on Page 3750 of the Telerate screen as of 11:00 A.M., London time, two Business Days prior to the beginning of such Interest Period. In the event that such rate does not appear on Page 3750 of the Telerate screen (or otherwise on such screen), the "Eurodollar Base Rate" for purposes of this definition shall be determined by reference to such other comparable publicly available service for displaying eurodollar rates as may be selected by the Administrative Agent.

"Eurodollar Loans" means Loans for which the applicable rate of interest is based upon the Eurodollar Rate.

"Eurodollar Rate" means with respect to each day during each Interest Period, a rate per annum determined for such day in accordance with the following formula (rounded upward to the nearest 1/100th of 1%):

Eurodollar Base Rate

1.00 - Eurocurrency Reserve Requirements

"Eurodollar Tranche" means the collective reference to Eurodollar Loans the then current Interest Periods with respect to all of which begin on the same date and end on the same later date (whether or not such Loans shall originally have been made on the same day).

"Event of Default" means any of the events specified in Section 7.1, provided that any requirement for the giving of notice, the lapse of time, or both, has been satisfied.

"Extensions of Credit" means, as to any Lender at any time, the sum of Tranche A Extensions of Credit and Tranche B Extensions of Credit of such Lender.

"Existing Letters of Credit" means the letters of credit described in Schedule 2.1.

"Facility Fee Rate" means as set forth in the Pricing Grid.

"Federal Funds Effective Rate" means for any day, the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System arranged by federal funds brokers, as published on the next succeeding Business Day by the Federal Reserve Bank of New York, or, if such rate is not so published for any day which is a Business Day, the average of the quotations for the day of such transactions received by the Reference Lender from three federal funds brokers of recognized standing selected by it.

"Federal Reserve System" means the Federal Reserve System of the United States of America.

"Financed Subsidiary" means any direct or indirect Subsidiary of the Borrower that is financed with Indebtedness of such Subsidiary.

"Financial Officer" of any Person means the chief financial officer, principal accounting officer, treasurer, associate or assistant treasurer, or any responsible officer analogous to the foregoing or designated by the one of the foregoing Persons, of such Person.

"Fitch" means Fitch, Inc.

"Fixed Charges" means, with respect to the Borrower for any period, the sum, without duplication, of (i) the aggregate amount of interest expense and commitment and other periodic fees with respect to Funded Indebtedness of the Borrower Scheduled to be Paid for such period, including (A) the net costs under Swaps, (B) all capitalized interest, (C) the interest portion of any deferred payment obligation and (D) the Lease Payment Obligations of the Borrower Scheduled to be Paid by the Borrower during such period, and (ii) the aggregate amount of all mandatory scheduled payments (whether designated as payments or prepayments) and scheduled sinking fund payments with respect to principal of any Funded Indebtedness of the Borrower, including payments in the nature of principal under Lease Obligations, provided that with respect to any Funded Indebtedness of the Borrower consisting of Equity Funding Arrangements, "Fixed Charges" shall not include any of the foregoing enumerated items to the extent paid by a Subsidiary of the Borrower (so long as the funds used to make such payments were not provided by the Borrower).

"Funded Indebtedness" of a Person means all Indebtedness of such Person (after intercompany eliminations) other than any Guaranty obligations that are not reasonably quantifiable under standard accounting practices as of the date of determination.

"Funding Office" means the office of the Administrative Agent specified in Section 9.2 or such other office as may be specified from time to time by the Administrative Agent as its funding office by written notice to the Borrower and the Lenders.

"GAAP" means generally accepted accounting principles in the United States of America as in effect from time to time.

"Government Authority" means any Federal, state, county, municipal or other local governmental authority or judicial or regulatory agency, board, body, commission or instrumentality.

"Governmental Approvals" means all authorizations, consents, approvals, licenses and exemptions of, registrations and filings with, and notices and reports to all Governmental Authorities.

"GTN" means PG&E Gas Transmission, Northwest Corporation, a California corporation.

"GTN Credit Agreements" means (i) the $750,000,000 Indenture, dated as of May 22, 1995, between GTN and The First National Bank of Chicago, as trustee and (ii) the $100,000,000 Amended and Restated Credit Agreement, dated May 24, 1999, between GTN, the lenders party thereto and Citicorp USA, Inc., as administrative agent for such lenders, including any commercial paper supported by credit facilities made available under such credit agreements, as the same may be amended, modified or supplemented from time to time.

"Guaranty" means (a) a guaranty by a Person (other than by endorsement of negotiable instruments for collection in the ordinary course of business), directly or indirectly, in any manner, of any part or all of the obligations of another Person; and (b) an agreement by a Person, direct or indirect, contingent or otherwise, and whether or not constituting a guaranty, the practical effect of which is to assure the payment or performance (or payment of damages in the event of nonperformance) of any part or all of the obligations of another Person (other than in respect of operating leases not otherwise included in the definition of "Lease Obligations"), whether by (i) the purchase of securities or obligations, (ii) the purchase, sale or lease of property or the purchase or sale of services primarily for the purpose of enabling the obligor with respect to such obligation to make any payment or performance (or payment of damages in the event of nonperformance) of or on account of any part or all of such obligation, or to assure the obligee of such obligation against loss, (iii) repayment of amounts drawn down by beneficiaries of letters of credit, (iv) the maintenance of working capital, equity capital, available cash or other financial statement condition so as to enable the primary obligor to pay Indebtedness; (v) the provision of equity or other capital under or in respect of equity or other capital subscription arrangements, (vi) the supplying of funds to or investing in a Person on account of all or any part of such Person's obligation or indemnifying or holding harmless, in any way, such Person against any

part or all of such obligation or (vii) the placing of any Lien on property (including, without limitation, accounts and contract rights) of a Person to secure another Person's Indebtedness.

"Indebtedness" of any Person means (i) all indebtedness of such Person for borrowed money, (ii) all obligations of such Person evidenced by bonds, debentures, notes or other similar instruments, (iii) all obligations of such Person to pay the deferred purchase price of property or services, (iv) all indebtedness created or arising under any conditional sale or other title retention agreement with respect to property acquired by such Person (even though the rights and remedies of the seller or lender under such agreement in the event of default are limited to repossession or sale of such property), (v) all Lease Obligations of such Person, (vi) all obligations, contingent or otherwise, of such Person under any issued and outstanding acceptance, letter of credit or similar instruments, (vii) all obligations of such Person to redeem or purchase any capital stock of such Person which is mandatorily redeemable,
(viii) all Swaps of such Person and (ix) any Guaranty of such Person with respect to liabilities of the type described in clauses (i) through (viii) hereof.

"Indemnified Liabilities" has the meaning given such term in Section 9.5.

"Indemnitee" has the meaning given such term in Section 9.5.

"Interest Payment Date" means (a) as to any Base Rate Loan, the last day of each March, June, September and December to occur while such Loan is outstanding and the final maturity date of such Loan, (b) as to any Eurodollar Loan having an Interest Period of three months or shorter, the last day of such Interest Period, (c) as to any Eurodollar Loan having an Interest Period longer than three months, each day that is three months, or a whole multiple thereof, after the first day of such Interest Period and the last day of such Interest Period and (d) as to any Loan, the date of any repayment or prepayment made in respect thereof.

"Interest Period" means as to any Eurodollar Loan, (a) initially, the period commencing on borrowing date or the conversion date, as the case may be, with respect to such Eurodollar Loan and ending one, two, three or six months thereafter, as selected by the Borrower in its notice of borrowing or of conversion, as the case may be, given with respect thereto; and (b) thereafter, each period commencing on the last day of the next preceding Interest Period applicable to such Eurodollar Loan and ending one, two, three or six months thereafter, as selected by the Borrower by irrevocable notice to the Administrative Agent not less than three Business Days prior to the last day of the then current Interest Period with respect thereto; provided that, all of the foregoing provisions relating to Interest Periods are subject to the following:

(i) if any Interest Period would otherwise end on a day that is not a Business Day, such Interest Period shall be extended to the next succeeding Business Day unless the result of such extension would be to carry such Interest Period into another calendar month in which event such Interest Period shall end on the immediately preceding Business Day;

(ii) any Interest Period that would otherwise extend beyond the Termination Date or beyond the date final payment is due on any Loan shall end on the Termination Date or such due date, as applicable; and

(iii) any Interest Period that begins on the last Business Day of a calendar month (or on a day for which there is no numerically corresponding day in the calendar month at the end of such Interest Period) shall end on the last Business Day of the calendar month at the end of such Interest Period.

"Investment" means the acquisition of any interest in any Person or property, a loan or advance to any Person or other arrangement for the purpose of providing funds or credit to any Person, a capital contribution in or to any Person, or any other investment in any Person or property, or any Guaranty of any of the foregoing.

"Investment Vehicle" means each Subsidiary of the Borrower which is organized solely to acquire, make or hold one or more Investments in an Asset Company or Asset Companies, either directly or indirectly through one or more other Investment Vehicles.

"Issuing Bank" has the meaning given such term in the preamble hereto.

"L/C Fee Payment Date" means the last day of each March, June, September and December and the last day of the Tranche A Commitment Period or Tranche B Commitment Period, whichever is applicable.

"L/C Obligations" means at any time, an amount equal to the sum of the Tranche A L/C Obligations and the Tranche B L/C Obligations.

"L/C Participants" means the Tranche A L/C Participants and the Tranche B L/C Participants.

"Lease Obligations" means, without duplication, (i) any Indebtedness represented by obligations under a lease that is required to be capitalized for financial reporting purposes and (ii) the present value, determined using a discount rate equal to the incremental borrowing rate (as defined in Statement of Financial Accounting Standards No. 13) of the Person incurring such obligations, of rent obligations under leases of electric generating assets or natural gas pipelines and related facilities.

"Lease Payment Obligations" means, with respect to any Person for any period, (i) the interest component of all Lease Obligations of such Person that are described in clause (i) of the definition of "Lease Obligations" and that are Scheduled to be Paid during such period, plus (ii) the principal portion of all Lease Obligations of such Person that are described in clause (i) of the definition of "Lease Obligations" that are Scheduled to be Paid during such period, plus (iii) all rent payment obligations relating to Lease Obligations of such Person described in clause (ii) of the definition of "Lease Obligations" and that are Scheduled to be Paid during such period.

"Lender Affiliate" (a) any Affiliate of any Lender, (b) any Person that is administered or managed by any Lender and that is engaged in making, purchasing, holding or otherwise investing in commercial loans and similar extensions of credit in the ordinary course of its business and (c) with respect to any Lender which is a fund that invests in commercial loans and similar extensions of credit, any other fund that invests in commercial loans and similar extensions of credit and is managed or advised by the same investment advisor as such Lender or by an Affiliate of such Lender or investment advisor.

"Lenders" has the meaning given such term in the preamble hereto; provided, that unless the context otherwise requires, each reference herein to the Lenders shall be deemed to include any Conduit Lender.

"Letter Agreement" means the Letter Agreement, dated as of August 22, 2001, from NEG LLC addressed to the Administrative Agent, for the benefit of the Lenders.

"Letters of Credit" means the Tranche A Letters of Credit and the Tranche B Letters of Credit.

"Lien" means, with respect to any asset, any mortgage, lien, pledge, charge, security interest or encumbrance of any kind in respect of such asset or any interest or title of a vendor or lessor under any conditional sale agreement, capital lease or other title retention agreement relating to such asset.

"Loan Documents" means this Agreement, the Applications for Issuance and the Notes.

"Loans" means, as to any Lender, the Tranche A Loans and Tranche B Loans made by such Lender.

"Margin Stock" has the meaning given such term under Regulation U.

"Material Adverse Effect" means a material adverse effect on (a) the business, assets, property, condition (financial or otherwise) or prospects of Borrower and its Subsidiaries taken as a whole or (b) the validity or enforceability of this Agreement or any of the other Loan Documents or the rights or remedies of the Administrative Agent or the Lenders hereunder or thereunder.

"Material Plan" means any Plan or Plans having aggregate Unfunded Liabilities in excess of $50,000,000.

"Minimum Consolidated Net Worth" means $1.8 billion.

"Minimum Non-Trading Consolidated Net Worth" means $1.4 billion.

"Moody's" means Moody's Investors Service, Inc.

"Multiemployer Plan" means a multiemployer plan as defined in Section 4001(a)(3) of ERISA to which the Borrower or any ERISA Affiliate is making, or accruing an obligation to make, contributions, or has within any of the preceding six years made, or accrued an obligation to make, contributions.

"NEG Guarantees" means (i) the Guarantee and Agreement (La Paloma), dated as of April 6, 2001, made by the Borrower in favor of Citibank, N.A., for the benefit of the creditors identified therein, (ii) the Guarantee and Agreement (Lake Road), dated as of April 6, 2001, made by the Borrower in favor of Citibank, N.A., for the benefit of the creditors identified therein, (iii) the Guarantee and Agreement (Harquahala), dated as of April 30, 2001, made by the Borrower in favor of State Street Bank and Trust Company, for the benefit of the creditors

identified therein and (iv) the Guarantee and Agreement (Turbine Credit Agreement), dated as of May 29, 2001, made by the Borrower in favor of Societe Generale, for the benefit of the lenders identified therein, as each may be amended, modified or supplemented from time to time.

"NEG Indenture" means the Indenture, dated as of May 22, 2001, between the Borrower and Wilmington Trust Company, as trustee.

"NEG LLC" means PG&E National Energy Group, LLC, a Delaware limited liability company.

"Non-Excluded Taxes" has the meaning given such term in Section 3.14(a).

"Non-Trading Consolidated Net Worth" means, as of any date of determination thereof, the amount which would be reflected as stockholders' equity upon a consolidated balance sheet of the Borrower (but excluding any portion thereof attributable to (i) Unrestricted Subsidiaries or (ii) ET Holdings or any Subsidiary thereof) excluding other comprehensive income arising from the accounting treatment of hedging and mark-to-market transactions.

"Non-U.S. Lender" has the meaning given such term in Section 3.14(d).

"Note" means any promissory note evidencing any Loan.

"Obligations" means the unpaid principal of and interest on (including, without limitation, interest accruing after the maturity of the Loans and interest accruing after the filing of any petition in bankruptcy, or the commencement of any insolvency, reorganization or like proceeding, relating to the Borrower, whether or not a claim for post-filing or post-petition interest is allowed in such proceeding) the Loans and all other obligations and liabilities of the Borrower to the Administrative Agent or to any Lender, whether direct or indirect, absolute or contingent, due or to become due, or now existing or hereafter incurred, which may arise under, out of, or in connection with, this Agreement, any other Loan Document, the Letters of Credit or any other document made, delivered or given in connection herewith or therewith, whether on account of principal, interest, reimbursement obligations, fees, indemnities, costs, expenses (including, without limitation, all fees, charges and disbursements of counsel to the Administrative Agent or to any Lender that are required to be paid by the Borrower pursuant hereto) or otherwise.

"Other Taxes" means any and all present or future stamp or documentary taxes or any other excise or property taxes, charges or similar levies arising from any payment made hereunder or from the execution, delivery or enforcement of, or otherwise with respect to, this Agreement or any other Loan Document.

"Participant" means as defined in Section 9.6(b).

"Payment Amount" has the meaning given such term in Section 2.4.

"Payment Office" means the office specified from time to time by the Administrative Agent as its payment office by notice to the Borrower and the Lenders.

"PBGC" means the Pension Benefit Guaranty Corporation established pursuant to Subtitle A of Title IV of ERISA (or any successor).

"Permitted Encumbrances" means, as to any Person at any date, any of the following:

(i) Liens for taxes, assessments or governmental charges not then delinquent, and Liens for taxes, assessments or governmental charges then delinquent but the validity of which is being contested at the time by such Person in good faith and for which adequate reserves have been established in accordance with GAAP, and (ii) Liens incurred or created in connection with or to secure the performance of bids, tenders, contracts (other than for the payment of money), leases, statutory obligations, surety bonds or appeal bonds, and carriers', warehousemen's, mechanics' or materialmen's Liens, assessments or similar encumbrances incurred in the ordinary course of business;

(ii) easements, restrictions, exceptions or reservations in any property and/or rights of way of such Person for the purpose of roads, pipe lines, substations, transmission lines, transportation lines, distribution lines, removal of oil, gas, lignite, 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, and defects, irregularities and deficiencies in titles of any property and/or rights of way, which do not individually or in the aggregate materially impair the use or value of such property and/or rights of way for the purposes for which such property and/or rights of way are held by such Person;

(iii) rights reserved to or vested in any municipality or public authority to use, control or regulate any property of such Person;

(iv) any obligations or duties, affecting the property of such Person, to any municipality or public authority with respect to any franchise, grant, license or permit;

(v) any judgment Lien against such Person securing a judgment for an amount not exceeding $50,000,000, so long as the finality of such judgment is being contested by appropriate proceedings conducted in good faith and execution thereon is stayed;

(vi) any Lien arising by reason of deposits with or giving of any form of security to any federal, state, municipal or other governmental department, commission, board, bureau, agency or instrumentality, domestic or foreign, for any purpose at any time as required by law or governmental regulation as a condition to the transaction of any business or the exercise of any privilege or license, or to enable such Person to maintain self-insurance or to participate in any fund for liability on any insurance risks or in connection with workers' compensation, unemployment insurance, old age pensions or other social security or to share in the privileges or benefits required for companies participating in such arrangements; or

(vii) any landlords' Lien on fixtures or movable property located on premises leased by such Person in the ordinary course of business so long as the rent secured thereby is not in default.

"Permitted Sale-Leaseback Transactions" means (i) Sale-Leaseback transactions by any Restricted Subsidiary or Asset Company, entered into on or prior to the date of this Credit Agreement and identified on Schedule 6.12(j) and (ii) one or more Sale/Leaseback transactions entered into by any Asset Company in connection with or as part of a Project Financing Facility entered into after the date of execution of this Agreement.

"Permitted Subordinated Indebtedness" means all unsecured Indebtedness of the Borrower that shall have been subordinated to all Indebtedness of the Borrower under this Agreement and otherwise containing terms and conditions set forth in Schedule 6.12(h)-1 with respect to Indebtedness of the Borrower to Affiliates of the Borrower or in Schedule 6.12(h)-2 with respect to Indebtedness of the Borrower to non-Affiliates of the Borrower.

"Person" means an individual, partnership, corporation, limited liability company, business trust, joint stock company, trust, unincorporated association, joint venture, Governmental Authority or other entity of whatever nature.

"PG&E" means Pacific Gas & Electric Company, a California corporation.

"PG&E Corp." means PG&E Corporation, a California corporation.

"PG&E Gen" means PG&E Generating Company, LLC, a Delaware limited liability company, formerly known as U.S. Generating Company, LLC.

"PG&E Gen Credit Agreement" means the $10,000,000 Credit Agreement, dated as of December 14, 1999, between PG&E Gen and ABN AMRO Bank N.V., as each may be amended, modified or supplemented from time to time.

"Plan" means any employee pension benefit plan described under Section 3(2) of ERISA (other than a Multiemployer Plan) subject to the provisions of Title IV of ERISA that is maintained by the Borrower or any ERISA Affiliate or with respect to which the Borrower or any ERISA Affiliate could have liability under Section 4069 of ERISA.

"Pricing Grid" means as set forth in Schedule 1.1A.

"Prime Rate" means the rate of interest per annum publicly announced from time to time by the Reference Lender as its prime or base rate in effect at its principal office in New York City.

"Project Financing Facility" means any loan, note purchase agreement, indenture, lease, credit agreement, reimbursement agreement, letter of credit or other facility pursuant to which an Asset Company or Investment Vehicle which directly or indirectly owns an Asset Company incurs Indebtedness, provided that any such Indebtedness is recourse only to (a) the assets of such Asset Company or any Asset Company which is a Subsidiary of such Asset Company, (b) the equity or ownership interests of such Asset Company or any Investment Vehicle which owns such Asset Company or (c) any Equity Funding Arrangements provided with respect to such Asset Company or Investment Vehicle or a Lien on any such Equity Funding Arrangements.

"Projections" means the projections dated July 10, 2001 provided to the Administrative Agent by the Borrower.

"PUHCA" means the Public Utility Holding Company Act of 1935, as amended.

"Ratio of Cash Flow to Fixed Charges" means, as of the end of each fiscal quarter of the Borrower, the ratio of (a) Cash Flow Available for Fixed Charges of the Borrower for the period of four consecutive fiscal quarters ending on, or most recently ended prior to, such date to (b) Fixed Charges of the Borrower for such period, excluding from the calculation of Fixed Charges all Trading Arrangements and Credit Support Arrangements.

"Ratio of Debt to Capitalization" means, as of any date, the ratio of the aggregate principal amount of Funded Indebtedness of the Borrower to the Total Capitalization of the Borrower (excluding from the calculation of Funded Indebtedness all Trading Arrangements, Credit Support Arrangements and Swaps); provided that any Equity Funding Arrangements shall only be included in Funded Indebtedness in an amount equal to the lesser of (x) the maximum amount that would be payable under such Equity Funding Arrangements (assuming a drawing is permissible as of the date of determination) and (y) the amount outstanding under any underlying Indebtedness to which any payment under such Equity Funding Arrangements would be applied (assuming such Indebtedness were due and payable as of the date of determination).

"Reference Lender" means The Chase Manhattan Bank.

"Refinanceable Facilities" has the meaning ascribed thereto in Section 6.12(a).

"Register" has the meaning given such term in Section 9.6(d).

"Regulation U" means Regulation U of the Board as in effect from time to time.

"Reimbursement Date" has the meaning given such term in Section 2.4.

"Reimbursement Obligation" means the obligation of the Borrower to reimburse the Issuing Bank pursuant to Section 2.5 for amounts drawn under Letters of Credit issued by the Issuing Bank.

"Repurchase Agreement" means any written agreement:

(i) that provides for (i) the transfer of one or more United States or Canadian Governmental Securities or any security issued by a U.S. agency or instrumentality in an aggregate principal amount at least equal to the amount of the Transfer Price (defined below) to the Borrower or any Restricted Subsidiary from a financial institution that is (1) a member of the Federal Reserve System having a minimum of US$20 billion in assets, and
(2) has commercial paper rated at least A-1 by S&P, at least F1 by Fitch or at least P-1 by Moody's, against a transfer of funds (the "Transfer Price") by the Borrower or such Restricted Subsidiary to such financial institution and (ii) a simultaneous agreement by the Borrower or such Restricted Subsidiary, in connection with such transfer of funds, to transfer to such financial institution the same or substantially similar United

States or Canadian Governmental Securities or any security issued by a U.S. agency or instrumentality for a price not less than the Transfer Price plus a reasonable return thereon at a date certain not later than 180 days after such transfer of funds,

(ii) in respect of which the Borrower or such Restricted Subsidiary shall have the right, whether by contract or pursuant to applicable law, to liquidate such agreement upon the occurrence of any default thereunder, and

(iii) in connection with which the Borrower or such Restricted Subsidiary, or an agent thereof, shall have taken all action required by applicable law or regulations to perfect a Lien in such United States or Canadian Governmental Securities or any security issued by a U.S. agency or instrumentality.

"Required Lenders" means at any time, (i) with respect to Tranche A Loans or Tranche A Letters of Credit, Tranche A Lenders whose Tranche A Aggregate Exposure Percentages are, in the aggregate, greater than 50%, (ii) with respect to Tranche B Loans or Tranche B Letters of Credit, Tranche B Lenders whose Tranche B Aggregate Exposure Percentages are, in the aggregate, greater than 50% and (iii) in all other cases, Lenders whose Aggregate Exposure Percentages are, in the aggregate, greater than 50%.

"Requirement of Law" means as to any Person, the Certificate of Incorporation and By-Laws or other organizational or governing documents of such Person, and any law, treaty, rule or regulation or determination of an arbitrator or a court or other Governmental Authority, in each case applicable to or binding upon such Person or any of its property or to which such Person or any of its property is subject.

"Responsible Officer" of the Borrower, shall mean any president or senior vice president of the Borrower.

"Restricted Subsidiary" means any Subsidiary of the Borrower that is not (x) an Asset Company, (y) an Investment Vehicle or (z) an Unrestricted Subsidiary.

"S&P" means Standard & Poor's Ratings Service, a division of McGraw Hill Companies, Inc.

"Sale/Leaseback" means any lease whereby any Person becomes or remains liable as lessee or as Borrower or other surety of any property, whether now owned or hereafter acquired, that such Person has sold or transferred or is to sell or transfer to any other Person (other than any Subsidiary of such Person), as part of a financing transaction to which such Person is a party, in contemplation of leasing such property to such Person.

"Scheduled to be Paid" means, with respect to any liability or expense for any period, the amount of such liability or expense scheduled to be paid during such period or the amount of such liability or expense that would have been scheduled to be paid during such period had the payment schedule with respect to such liability or expense been divided equally into successive periods having a duration equal to the duration of such period.

"SEC" means the Securities and Exchange Commission (or successors thereto or an analogous Governmental Authority).

"Subsidiary" means, with respect to any Person (the "Parent"), any corporation or other entity of which sufficient securities or other ownership interests having ordinary voting power to elect a majority of the board of directors or other Persons performing similar functions are at the time directly or indirectly owned by such Parent.

"Swaps" means, with respect to any Person, payment obligations with respect to interest rate swaps, currency swaps and similar obligations obligating such Person to make payments, whether periodically or upon the happening of a contingency. The amount of the obligation under any Swap shall be the amount determined in respect thereof as of the end of the then most recently ended fiscal quarter of such Person, based on the assumption that such Swap had terminated at the end of such fiscal quarter, and in making such determination, if any agreement relating to such Swap provides for the netting of amounts payable by and to such Person thereunder or if any such agreement provides for the simultaneous payment of amounts by and to such Person, then in each such case, the amount of such obligation shall be the net amount so determined.

"Syndication Agents" has the meaning given such term in the preamble hereto.

"Termination Date" means either the Tranche A Termination Date or the Tranche B Termination Date, whichever is applicable.

"Total Capitalization" means, with respect to the Borrower, the sum, without duplication, of (i) total common stock equity or analogous ownership interests of the Borrower, (ii) preferred stock and preferred securities of the Borrower, (iii) additional paid in capital or analogous interests of the Borrower, (iv) retained earnings of the Borrower, excluding other comprehensive income arising from accounting treatment of hedging and mark-to-market transactions and (v) the aggregate principal amount of Funded Indebtedness of the Borrower.

"Total Commitments" means at any time, the aggregate amount of Tranche A Commitments and Tranche B Commitments of all Lenders then in effect. The original amount of Total Commitments is One Billion and Two Hundred Fifty Million Dollars ($1,250,000,000).

"Total Extensions of Credit" means at any time, the aggregate amount of Extensions of Credit of all Lenders outstanding at such time.

"Trading Arrangement" means any transaction entered into by PG&E Energy Trading - Power, L.P., a Delaware limited partnership, PG&E Energy Trading Gas Corporation, a California corporation, or PG&E Energy Trading, Canada Corporation, an Alberta corporation, any other Restricted Subsidiary, Asset Company or Investment Vehicle, whether pursuant to master trading agreements or otherwise, for (1) the purchase and sale of energy, capacity, ancillary services and other energy or energy-related products, including transmission rights, environmental allowances and offsets and storage; (2) the purchase and sale of natural gas, coal, oil and other fuel, including transportation and storage rights; (3) the purchase and sale of fuel conversion services, including tolling arrangements; (4) the purchase and sale of any energy or energy-related derivatives, including weather derivatives; (5) hedging arrangements with respect

to any of the foregoing and interest rate, foreign currency or credit exposure; or (6) any similar arrangements entered into in the ordinary course of business as conducted by such Persons or by other Persons in the energy trading, energy services, power generating, electric transmission or gas transmission and storage businesses (including technologies related to such businesses).

"Tranche A Aggregate Exposure" means with respect to any Lender at any time, an amount equal to the amount of such Lender's Tranche A Commitment at such time or, if the Tranche A Commitments have been terminated, the amount of such Lender's Tranche A Loans then outstanding.

"Tranche A Aggregate Exposure Percentage" means with respect to any Lender at any time, the ratio (expressed as a percentage) of such Lender's Tranche A Aggregate Exposure at such time to the sum of the Tranche A Aggregate Exposures of all Lenders at such time.

"Tranche A Commitment" means as to any Lender, the obligation of such Lender to make Tranche A Loans and participate in Tranche A Letters of Credit pursuant to the terms hereof, in an aggregate principal and/or stated amount not to exceed the amount set forth under the heading "Tranche A Commitment" opposite such Lender's name (i) on Schedule 1.1 or (ii) in the Assignment and Acceptance pursuant to which such Lender became a party hereto, as applicable, as the same may be changed from time to time pursuant to the terms hereof.

"Tranche A Commitment Period" means the period from and including the Closing Date to the Tranche A Termination Date.

"Tranche A Extensions of Credit" means as to any Tranche A Lender at any time, an amount equal to the sum of (a) the aggregate principal amount of all Tranche A Loans made by such Lender then outstanding and (b) such Tranche A Lender's Aggregate Exposure Percentage of the Tranche A L/C Obligations then outstanding.

"Tranche A L/C Obligations" means at any time, an amount equal to the sum of (a) the aggregate of the stated amounts of the then outstanding Tranche A Letters of Credit and (b) the aggregate amount of drawings under Tranche A Letters of Credit that have not been reimbursed pursuant to Section 2.4(a)(i).

"Tranche A L/C Participants" means all the Tranche A Lenders other than the Issuing Bank.

"Tranche A Lender" means each Lender that has a Tranche A Commitment or that holds a Tranche A Loan.

"Tranche A Letters of Credit" has the meaning given to such term in
Section 2.1(a).

"Tranche A Loans" has the meaning given to such term in Section 3.1(a)(i).

"Tranche A Termination Date" means the date which is two years from the Closing Date, subject to extension in accordance with Section 3.19.

"Tranche B Aggregate Exposure" means with respect to any Lender at any time, an amount equal to the amount of such Lender's Tranche B Commitment at such time or, if the Tranche B Commitments have been terminated, the amount of such Lender's Tranche B Loans then outstanding.

"Tranche B Aggregate Exposure Percentage" means with respect to any Lender at any time, the ratio (expressed as a percentage) of such Lender's Tranche B Aggregate Exposure at such time to the sum of the Tranche B Aggregate Exposures of all Lenders at such time.

"Tranche B Commitment" means as to any Lender, the obligation of such Lender to make Tranche B Loans and participate in Tranche B Letters of Credit pursuant to the terms hereof, in an aggregate principal and/or stated amount not to exceed the amount set forth under the heading "Tranche B Commitment" opposite such Lender's name (i) on Schedule 1.1 or (ii) in the Assignment and Acceptance pursuant to which such Lender became a party hereto, as applicable, as the same may be changed from time to time pursuant to the terms hereof.

"Tranche B Commitment Period" means the period from and including the Closing Date to the Tranche B Termination Date.

"Tranche B Extensions of Credit" means as to any Tranche B Lender at any time, an amount equal to the sum of (a) the aggregate principal amount of all Tranche B Loans made by such Lender then outstanding and (b) such Tranche B Lender's Aggregate Exposure Percentage of the Tranche B L/C Obligations then outstanding.

"Tranche B L/C Limit" means $150 million.

"Tranche B L/C Obligations" means at any time, an amount equal to the sum of (a) the aggregate of the stated amounts of the then outstanding Tranche B Letters of Credit and (b) the aggregate amount of drawings under Tranche B Letters of Credit that have not been reimbursed pursuant to Section 2.4(a)(ii).

"Tranche B L/C Participants" means all the Tranche B Lenders other than the Issuing Bank.

"Tranche B Lender" means each Lender that has a Tranche B Commitment or that holds a Tranche B Loan.

"Tranche B Letters of Credit" has the meaning given to such term in
Section 2.1(b).

"Tranche B Loans" has the meaning given to such term in Section 3.1(b)(i).

"Tranche B Termination Date" means the date which is 364 days from the Closing Date, subject to extension in accordance with Section 3.19.

"Transferee" has the meaning given such term in Section 9.15.

"Type" means as to any Loan, its nature as a Base Rate Loan or a Eurodollar Loan.

"Unfunded Liabilities" means, with respect to any Plan at any time, the amount (if any) by which (i) the value of all benefit liabilities under such Plan, determined on a plan termination basis using the assumptions prescribed by the PBGC for purposes of Section 4044 of ERISA, exceeds (ii) the fair market value of all Plan assets allocable to such liabilities under Title IV of ERISA (excluding any accrued but unpaid contributions), all determined as of the then most recent valuation date for such Plan, but only to the extent that such excess represents a potential liability of the Borrower or any ERISA Affiliate to the PBGC or any other Person under Title IV of ERISA.

"United States" or "U.S." or "US" means the United States of America.

"Unrestricted Subsidiary" means any Subsidiary of the Borrower designated as such on the Closing Date, or, after the Closing Date, designated as such at the time of formation thereof or, if acquired by the Borrower, at the time of acquisition thereof, but, in any such case, only if at such time (i) no Event of Default, Incipient Event of Default or Downgrade Event has occurred and is continuing or would occur as a result thereof and (ii) such Subsidiary or any of its Subsidiaries does not own any capital stock or Indebtedness of or have any Investment in, or own or hold any Lien on any property of, any other Subsidiary of the Borrower which is not a Subsidiary of the Subsidiary to be so designated or otherwise an Unrestricted Subsidiary.

"USGenNE" means USGen New England, Inc., a Delaware corporation and an indirect, wholly-owned Subsidiary of the Borrower.

"USGenNE Credit Agreement" means the $575,000,000 Credit Agreement, dated as of September 1, 1998, among USGenNE, the lenders party thereto, The Chase Manhattan Bank, as competitive advance facility agent and as administrative agent for the lenders thereunder, and The Chase Manhattan Bank, as the issuer of letters of credit thereunder, as the same may be amended, modified or supplemented from time to time.

Other Definitional Provisions.

The following rules of usage shall apply unless otherwise required by the context or unless otherwise specified herein:

(b) Definitions set forth herein shall be equally applicable to the singular and plural forms of the terms defined.

(c) References in this Agreement to articles, sections, paragraphs, clauses, annexes, appendices, schedules or exhibits are references to articles, sections, paragraphs, clauses, annexes, appendices, schedules or exhibits in such document.

(d) The headings, subheadings and table of contents used herein are solely for convenience of reference and shall not constitute a part hereof nor shall they affect the meaning, construction or effect of any provision hereof.

(e) References to any Person shall include such Person, its successors and permitted assigns and transferees.

(f) Reference to any agreement means such agreement as amended, supplemented or otherwise modified from time to time in accordance with the applicable provisions thereof.

(g) References to any law includes any amendment or modification to such law and any rules or regulations issued thereunder or any law enacted in substitution or replacement thereof.

(h) The words "hereof," "herein", "hereto" and "hereunder" and words of similar import when used in this Agreement shall refer to this Agreement as a whole and not to any particular provision of this Agreement.

(i) References to "including" means including without limiting the generality of any description preceding such term and for purposes hereof the rule of ejusdem generis shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

(j) Each of the parties to this Agreement and their counsel have reviewed and revised, or requested revisions to this Agreement, and the usual rule of construction that any ambiguities are to be resolved against the drafting party shall be inapplicable in the construing and interpretation of this Agreement and any amendments hereto and the other Loan Documents.

(k) Except as otherwise expressly provided herein, all terms of an accounting or financial nature shall be construed in accordance with GAAP, as in effect from time to time; provided that for purposes of determining compliance with any covenant set forth herein, such terms shall be construed in accordance with GAAP as in effect on the date hereof applied on a basis consistent with the application used in preparing the Borrower's audited financial statements.

ARTICLE II

LETTERS OF CREDIT

SECTION 2.1 L/C Commitment.

(a) Prior to the Closing Date, the Issuing Bank has issued the Existing Letters of Credit which, from and after the Closing Date, shall constitute Tranche A Letters of Credit hereunder. Subject to the terms and conditions hereof, the Issuing Bank, in reliance on the agreements of the Tranche A L/C Participants set forth in Section 2.4(a)(i), agrees to issue, from time to time, letters of credit (each letter of credit issued on and after the Closing Date pursuant to this Section 2.1(a) and each Existing Letter of Credit, a "Tranche A Letter of Credit", and collectively, the "Tranche A Letters of Credit") for the account of the Borrower on any Business Day during the Tranche A Commitment Period pursuant to the procedures set forth in Section 2.2; provided, that the Issuing Bank shall not issue any Tranche A Letter of Credit if, after giving effect to such issuance, the aggregate Tranche A Extensions of Credit of all Tranche A Lenders would exceed the aggregate Tranche A Commitments of all Tranche A Lenders. Each Tranche A Letter of Credit shall (i) be denominated in Dollars, (ii) be in a minimum stated

amount of $500,000 and (iii) expire no later than five Business Days prior to the Tranche A Termination Date.

(b) Subject to the terms and conditions hereof, the Issuing Bank, in reliance on the agreements of the Tranche B L/C Participants set forth in Section 2.4(a)(ii), agrees to issue, from time to time, letters of credit (each a "Tranche B Letter of Credit" and collectively, the "Tranche B Letters of Credit") for the account of the Borrower on any Business Day during the Tranche B Commitment Period pursuant to the procedures set forth in Section 2.2; provided, that the Issuing Bank shall not issue any Tranche B Letter of Credit if, after giving effect to such issuance, (i) the aggregate Tranche B Extensions of Credit of all Tranche B Lenders would exceed the aggregate Tranche B Commitments of all Tranche B Lenders or (ii) the aggregate of the stated amounts of all outstanding Tranche B Letters of Credit would exceed the Tranche B L/C Limit. Each Tranche B Letter of Credit shall (i) be denominated in Dollars, (ii) be in a minimum stated amount of $500,000 and (iii) expire no later than five Business Days prior to the Tranche B Termination Date.

(c) The Issuing Bank shall not at any time be obligated to issue any Letter of Credit hereunder if such issuance would conflict with, or cause the Issuing Bank or any L/C Participant to exceed any limits imposed by, any applicable Requirement of Law.

SECTION 2.2 Procedure for Issuance of Letter of Credit.

(a) Subject to the terms and conditions hereof, each Letter of Credit shall be issued (or the stated maturity thereof extended or terms thereof modified or amended) on not less than two Business Days' prior notice thereof waivable by the Administrative Agent by delivery to the address set forth in
Section 9.2 of an Application for Issuance to the Administrative Agent (which shall promptly distribute copies thereof to the Tranche A Lenders or Tranche B Lenders, whichever is applicable) and the Issuing Bank. Each Application for Issuance shall specify (i) the date (which shall be a Business Day) of issuance of such Letter of Credit (or the date of effectiveness of such extension, modification or amendment) and the stated expiry date thereof, (ii) the proposed stated amount of such Letter of Credit, (iii) the name and address of the beneficiary of such Letter of Credit and (iv) a statement of drawing conditions applicable to such Letter of Credit, and if such Application for Issuance relates to an amendment or modification of a Letter of Credit, it shall be accompanied by the consent of the beneficiary of the Letter of Credit thereto. Each Application for Issuance shall be irrevocable unless modified or rescinded by the Borrower not less than one day prior to the proposed date of issuance (or effectiveness) specified therein. Not later than 12:00 noon (New York City time) on the proposed date of issuance (or effectiveness) specified in such Application for Issuance, and upon fulfillment of the applicable conditions precedent and the other requirements set forth herein, the Issuing Bank shall issue (or extend, amend or modify) such Letter of Credit and provide notice and a copy thereof to the Borrower and the Administrative Agent, which shall promptly furnish copies thereof to the Tranche A Lenders or Tranche B Lenders, whichever is applicable.

SECTION 2.3 Fees and Other Charges.

(a) (i) The Borrower will pay to the Administrative Agent, for the account of the Tranche A Lenders, a fee on the stated amount of each outstanding Tranche A Letter of Credit at

a per annum rate equal to the Applicable Margin in effect from time to time with respect to Eurodollar Loans, shared ratably among the Tranche A Lenders in accordance with their respective Tranche A Aggregate Exposure Percentages and payable in arrears on each L/C Fee Payment Date after the issuance date of such Tranche A Letter of Credit.

(ii) The Borrower will pay to the Administrative Agent, for the account of the Tranche B Lenders, a fee on the stated amount of each outstanding Tranche B Letter of Credit at a per annum rate equal to the Applicable Margin in effect from time to time with respect to Eurodollar Loans, shared ratably among the Tranche B Lenders in accordance with their respective Tranche B Aggregate Exposure Percentages and payable in arrears on each L/C Fee Payment Date after the issuance date of such Tranche B Letter of Credit.

(b) The Borrower shall pay to the Issuing Bank, for its own account, a fronting fee at the rate of 0.10% per annum on the undrawn and unexpired amount of each Letter of Credit issued by it, payable in arrears on each L/C Fee Payment Date after the issuance date. In addition, the Borrower shall pay or reimburse the Issuing Bank on demand for such normal and customary fees and costs as are incurred or charged by the Issuing Bank in issuing, negotiating, effecting payment under, amending, cancelling or otherwise administering any Letter of Credit. A schedule of such normal and customary fees and costs is attached as Schedule 2.3(b).

SECTION 2.4 L/C Participations.

(a) (i) The Issuing Bank irrevocably agrees to grant and hereby grants to each Tranche A L/C Participant, and, to induce the Issuing Bank to issue Tranche A Letters of Credit, each Tranche A L/C Participant irrevocably agrees to accept and purchase and hereby accepts and purchases from the Issuing Bank, on the terms and conditions set forth below, for such Tranche A L/C Participant's own account and risk an undivided interest equal to such Tranche A L/C Participant's Tranche A Aggregate Exposure Percentage in the Issuing Bank's obligations and rights under and in respect of each Tranche A Letter of Credit and the amount of each draft paid by the Issuing Bank thereunder. Each Tranche A L/C Participant unconditionally and irrevocably agrees with the Issuing Bank that, if a draft is paid under any Tranche A Letter of Credit for which the Issuing Bank is not reimbursed in full by the Borrower in accordance with the terms of this Agreement, such Tranche A L/C Participant shall pay to the Issuing Bank upon demand at the Issuing Bank's address for notices specified herein an amount equal to such Tranche A L/C Participant's Tranche A Aggregate Exposure Percentage of the amount of such draft, or any part thereof, that is not so reimbursed.

(ii) The Issuing Bank irrevocably agrees to grant and hereby grants to each Tranche B L/C Participant, and, to induce the Issuing Bank to issue Tranche B Letters of Credit, each Tranche B L/C Participant irrevocably agrees to accept and purchase and hereby accepts and purchases from the Issuing Bank, on the terms and conditions set forth below, for such Tranche B L/C Participant's own account and risk an undivided interest equal to such Tranche B L/C Participant's Tranche B Aggregate Exposure Percentage in the Issuing Bank's obligations and rights under and in respect of each Tranche B Letter of Credit and the amount of each draft paid by the Issuing Bank thereunder. Each Tranche B L/C Participant unconditionally and irrevocably agrees with

the Issuing Bank that, if a draft is paid under any Tranche B Letter of Credit for which the Issuing Bank is not reimbursed in full by the Borrower in accordance with the terms of this Agreement, such Tranche B L/C Participant shall pay to the Issuing Bank upon demand at the Issuing Bank's address for notices specified herein an amount equal to such Tranche B L/C Participant's Tranche B Aggregate Exposure Percentage of the amount of such draft, or any part thereof, that is not so reimbursed.

(b) If any amount required to be paid by any L/C Participant to the Issuing Bank pursuant to Section 2.4(a) in respect of any unreimbursed portion of any payment made by the Issuing Bank under any Letter of Credit is paid to the Issuing Bank within three Business Days after the date such payment is due, such L/C Participant shall pay to the Issuing Bank on demand an amount equal to the product of (i) such amount, (ii) the daily average Federal Funds Effective Rate during the period from and including the date such payment is required to the date on which such payment is immediately available to the Issuing Bank, and
(iii) a fraction the numerator of which is the number of days that elapse during such period and the denominator of which is 360. If any such amount required to be paid by any L/C Participant pursuant to Section 2.4(a) is not made available to the Issuing Bank by such L/C Participant within three Business Days after the date such payment is due, the Issuing Bank shall be entitled to recover from such L/C Participant, on demand, such amount with interest thereon calculated from such due date at the rate per annum applicable to Base Rate Loans. A certificate of the Issuing Bank submitted to any L/C Participant with respect to any amounts owing under this Section shall be conclusive in the absence of manifest error.

(c) Whenever, at any time after the Issuing Bank has made payment under any Letter of Credit and has received from any L/C Participant its pro rata share of such payment in accordance with Section 2.4(a), the Issuing Bank receives any payment related to such Letter of Credit (whether directly from the Borrower or otherwise), or any payment of interest on account thereof, the Issuing Bank will distribute to such L/C Participant its pro rata share thereof; provided, however, that in the event that any such payment received by the Issuing Bank shall be required to be returned by the Issuing Bank, such L/C Participant shall return to the Issuing Bank the portion thereof previously distributed by the Issuing Bank to it.

SECTION 2.5 Reimbursement Obligation of the Borrower. The Borrower agrees to reimburse the Issuing Bank on the second Business Day next succeeding the Business Day on which the Issuing Bank notifies the Borrower of the date and amount of a draft presented under any Letter of Credit and paid by the Issuing Bank in the amount of (a) such draft so paid and (b) any taxes, fees, charges or other costs or expenses incurred by the Issuing Bank in connection with such payment. Each such payment shall be made to the Administrative Agent for disbursement to the Issuing Bank in Dollars and in immediately available funds. Interest shall be payable on any such amounts from the date on which the relevant draft is paid by the Issuing Bank until payment in full by the Borrower at the rate set forth in (i) until the second Business Day next succeeding the date of the relevant notice, Section 3.9(b) and (ii) thereafter, Section 3.9(c).

SECTION 2.6 Obligations Absolute. The Borrower's obligations under this Section 2 shall be absolute and unconditional under any and all circumstances and irrespective of any setoff, counterclaim or defense to payment that the Borrower may have or have had against the Issuing Bank, any beneficiary of a Letter of Credit or any other Person. The Borrower also agrees with the Issuing Bank that the Issuing Bank shall not be responsible for, and the Borrower's Reimbursement Obligations under Section 2.5 shall not be affected by, among other things, the validity or genuineness of documents or of any endorsements thereon, even though such documents shall in fact prove to be invalid, fraudulent or forged, or any dispute between or among the Borrower and any beneficiary of any Letter of Credit or any other party to which such Letter of Credit may be transferred or any claims whatsoever of the Borrower against any beneficiary of such Letter of Credit or any such transferee. The Issuing Bank shall not be liable for any error, omission, interruption or delay in transmission, dispatch or delivery of any message or advice, however transmitted, in connection with any Letter of Credit, except for errors or omissions found by a final and non-appealable decision of a court of competent jurisdiction to have resulted from the gross negligence or willful misconduct of the Issuing Bank. The Borrower agrees that any action taken or omitted by the Issuing Bank under or in connection with any Letter of Credit or the related drafts or documents, if done in the absence of gross negligence or willful misconduct and in accordance with the standards of care specified in the Uniform Commercial Code of the State of New York, shall be binding on the Borrower and shall not result in any liability of the Issuing Bank to the Borrower.

SECTION 2.7 Letter of Credit Payments. If any draft shall be presented for payment under any Letter of Credit, the Issuing Bank shall promptly notify the Borrower of the date and amount thereof. The responsibility of the Issuing Bank to the Borrower in connection with any draft presented for payment under any Letter of Credit shall, in addition to any payment obligation expressly provided for in such Letter of Credit, be limited to determining that the documents (including each draft) delivered under such Letter of Credit in connection with such presentment appear on their face to be in conformity with such Letter of Credit.

SECTION 2.8 Applications for Issuance. To the extent that any provision of any Application for Issuance is inconsistent with the provisions of this Section 2, the provisions of this Section 2 shall apply.

ARTICLE III

LOANS

SECTION 3.1 Loans.

(a) (i) Subject to the terms and conditions of this Agreement, each Tranche A Lender severally agrees to make revolving credit loans (the "Tranche A Loans") to the Borrower from time to time during the Tranche A Commitment Period in an aggregate principal amount at any one time outstanding which, when added to such Tranche A Lender's Tranche A Aggregate Exposure Percentage of the Tranche A L/C Obligations then outstanding does not exceed the amount of such Tranche A Lender's Tranche A Commitment. During the Tranche A Commitment Period, the Borrower may use the Tranche A Commitments by borrowing,

prepaying the Tranche A Loans in whole or in part, and reborrowing, all in accordance with the terms and conditions hereof.

(ii) The Borrower shall pay all outstanding Tranche A Loans on the Tranche A Termination Date.

(b) (i) Subject to the terms and conditions of this Agreement, each Tranche B Lender severally agrees to make revolving credit loans (the "Tranche B Loans") to the Borrower from time to time during the Tranche B Commitment Period in an aggregate principal amount at any one time outstanding which, when added to such Tranche B Lender's Tranche B Aggregate Exposure Percentage of the Tranche B L/C Obligations then outstanding does not exceed the amount of such Lender's Tranche B Commitment. During the Tranche B Commitment Period, the Borrower may use the Tranche B Commitments by borrowing, prepaying the Tranche B Loans in whole or in part, and reborrowing, all in accordance with the terms and conditions hereof.

(ii) The Borrower shall pay all outstanding Tranche B Loans on the Tranche B Termination Date.

(c) The Loans may from time to time be Eurodollar Loans or Base Rate Loans, as determined by the Borrower and notified to the Administrative Agent in accordance with this Section, Section 3.2 and Section 3.7.

SECTION 3.2 Procedure for Loan Borrowing. The Borrower may borrow under the Commitments during the Tranche A Commitment Period or Tranche B Commitment Period, whichever is applicable, on any Business Day, provided that the Borrower shall give the Administrative Agent irrevocable notice (which notice must be received by the Administrative Agent prior to 12:00 Noon, New York City time, (a) three Business Days prior to the requested Borrowing Date, in the case of Eurodollar Loans, or (b) one Business Day prior to the requested Borrowing Date, in the case of Base Rate Loans), specifying (i) the amount and Type of Loans to be borrowed, (ii) the requested Borrowing Date and (iii) in the case of Eurodollar Loans, the respective lengths of the initial Interest Period therefore (each, a "Notice of Borrowing"). Any Loans made on the Closing Date shall initially be Base Rate Loans. Each borrowing under the Commitments shall be in an amount equal to (x) in the case of Base Rate Loans, $1,000,000 or a whole multiple thereof (or, if the then aggregate Available Commitments are less than $1,000,000, such lesser amount) and (y) in the case of Eurodollar Loans, $1,000,000 or a whole multiple of $1,000,000 in excess thereof. Upon receipt of any such notice from the Borrower, the Administrative Agent shall promptly notify each Tranche A Lender and/or Tranche B Lender (as applicable) thereof. Each Tranche A Lender and/or Tranche B Lender, as applicable, will make the amount of its pro rata share of each borrowing available to the Administrative Agent for the account of the Borrower at the Funding Office prior to 12:00 Noon, New York City time, on the Borrowing Date requested by the Borrower in funds immediately available to the Administrative Agent. The proceeds of each such Loan shall be disbursed by the Administrative Agent in accordance with instructions provided by the Borrower in each Notice of Borrowing, which, if so specified in the applicable Notice of Borrowing, may be used to repay (1) with respect to Tranche A Loans, the Borrower's Reimbursement Obligations in respect of a drawing

under a Tranche A Letter of Credit and (2) with respect to Tranche B Loans, the Borrower's Reimbursement Obligations in respect of a drawing under a Tranche B Letter of Credit.

SECTION 3.3 Evidence of Debt.

(a) Each Lender shall maintain in accordance with its usual practice an account or accounts evidencing indebtedness of the Borrower to such Lender resulting from each Loan of such Lender from time to time, including the amounts of principal and interest payable and paid to such Lender from time to time under this Agreement.

(b) The Administrative Agent, on behalf of the Borrower, shall maintain the Register pursuant to Section 9.6(d), and a subaccount therein for each Lender, in which shall be recorded (i) the amount of each Loan made hereunder and any Note evidencing such Loan, the Type of such Loan and each Interest Period applicable thereto, (ii) the amount of any principal or interest due and payable or to become due and payable from the Borrower to each Lender hereunder and
(iii) both the amount of any sum received by the Administrative Agent hereunder from the Borrower and each Lender's share thereof.

(c) The entries made in the Register and the accounts of each Lender maintained pursuant to Section 3.3(a) shall, to the extent permitted by applicable law, be prima facie evidence of the existence and amounts of the obligations of the Borrower therein recorded; provided, however, that the failure of any Lender or the Administrative Agent to maintain the Register or any such account, or any error therein, shall not in any manner affect the obligation of the Borrower to repay (with applicable interest) the Loans made to the Borrower by such Lender in accordance with the terms of this Agreement.

(d) The Borrower agrees that, upon the request to the Administrative Agent by any Lender, the Borrower will promptly execute and deliver to such Lender a promissory note of the Borrower evidencing any Loans of such Lender, with appropriate insertions as to date and principal amount.

SECTION 3.4 Facility Fees, etc.

(a) The Borrower agrees to pay to the Administrative Agent for the account of each Lender a facility fee for the period from and including the Closing Date to the last day of the Tranche A Commitment Period or Tranche B Commitment Period, whichever is applicable, computed at the Facility Fee Rate on such Lender's Commitment during the period for which payment is made, payable quarterly in arrears on the last day of each March, June, September and December and on the Tranche A Termination Date or Tranche B Termination Date, whichever is applicable, commencing on the first of such dates to occur after the date hereof.

(b) The Borrower agrees to pay to each Agent the fees in the amounts and on the dates previously agreed to in writing by the Borrower and such Agent.

SECTION 3.5 Termination or Reduction of Commitments. (a) The Borrower shall have the right, upon not less than three Business Days' notice to the Administrative Agent, to terminate the Tranche A Commitments or, from time to time, to reduce the aggregate amount of the Tranche A Commitments; provided, that no such termination or reduction of Tranche A

Commitments shall be permitted if, after giving effect thereto and to any prepayments of the Tranche A Loans made on the effective date thereof, the aggregate Tranche A Extensions of Credit of all Tranche A Lenders would exceed the aggregate Tranche A Commitments of all Tranche A Lenders. Any such reduction shall be in an amount equal to $10,000,000, or a whole multiple thereof, and shall reduce permanently the Tranche A Commitments then in effect.

(b) The Borrower shall have the right, upon not less than three Business Days' notice to the Administrative Agent, to terminate the Tranche B Commitments or, from time to time, to reduce the aggregate amount of the Tranche B Commitments; provided, that no such termination or reduction of Tranche B Commitments shall be permitted if, after giving effect thereto and to any prepayments of the Tranche B Loans made on the effective date thereof, the aggregate Tranche B Extensions of Credit of all Tranche B Lenders would exceed the aggregate Tranche B Commitments of all Tranche B Lenders. Any such reduction shall be in an amount equal to $10,000,000, or a whole multiple thereof, and shall reduce permanently the Tranche B Commitments then in effect.

SECTION 3.6 Optional Prepayments; Mandatory Prepayments. The Borrower may at any time and from time to time prepay the Loans, in whole or in part, without premium or penalty, upon irrevocable notice delivered to the Administrative Agent at least three Business Days prior thereto in the case of Eurodollar Loans and at least one Business Day prior thereto in the case of Base Rate Loans, which notice shall specify the date and amount of such prepayment, and whether such prepayment is of Eurodollar Loans or Base Rate Loans; provided, that if a Eurodollar Loan is prepaid on any day other than the last day of the Interest Period applicable thereto, the Borrower shall also pay any amounts owing pursuant to Section 3.15. Upon receipt of any such notice the Administrative Agent shall promptly notify each relevant Lender thereof. If any such notice is given, the amount specified in such notice shall be due and payable on the date specified therein, together with accrued interest to such date on the amount prepaid. The principal amount of any prepayment received by the Administrative Agent shall be delivered to the relevant Lenders ratably in accordance with their Tranche A Aggregate Exposure Percentages or Tranche B Aggregate Exposure Percentages, whichever is applicable. Partial prepayments of Loans shall be in a minimum aggregate principal amount of the lesser of (i) $5,000,000 or (ii) the outstanding principal amount of the Loans being prepaid.

SECTION 3.7 Conversion and Continuation Options.

(a) The Borrower may elect from time to time to convert Eurodollar Loans to Base Rate Loans by giving the Administrative Agent at least two Business Days' prior irrevocable notice of such election, provided that any such conversion of Eurodollar Loans may be made only on the last day of an Interest Period with respect thereto. The Borrower may elect from time to time to convert Base Rate Loans to Eurodollar Loans by giving the Administrative Agent at least three Business Days' prior irrevocable notice of such election (which notice shall specify the length of the initial Interest Period therefor), provided that no Base Rate Loan may be converted into a Eurodollar Loan (i) when any Event of Default has occurred and is continuing and the Administrative Agent has, or the Required Lenders have, determined in its or their sole discretion not to permit such conversions or (ii) after the date that is one month prior to the final scheduled termination or maturity date of such Loan. Upon receipt of any such notice the Administrative Agent shall promptly notify each relevant Lender thereof.

(b) The Borrower may elect to continue any Eurodollar Loan as such upon the expiration of the then current Interest Period with respect thereto by giving irrevocable notice to the Administrative Agent, in accordance with the applicable provisions of the term "Interest Period" set forth in Section 1.1, of the length of the next Interest Period to be applicable to such Loans, provided that no Eurodollar Loan may be continued as such (i) when any Event of Default has occurred and is continuing and the Administrative Agent has, or the Required Lenders have, determined in its or their sole discretion not to permit such continuations or (ii) after the date that is one month prior to the final scheduled termination or maturity date of such Loan, and provided, further, that if the Borrower shall fail to give any required notice as described above in this paragraph or if such continuation is not permitted pursuant to the preceding proviso, such Loans shall be converted automatically to Base Rate Loans on the last day of such then expiring Interest Period. Upon receipt of any such notice the Administrative Agent shall promptly notify each relevant Lender thereof.

SECTION 3.8 Limitations on Eurodollar Tranches. Notwithstanding anything to the contrary in this Agreement, all borrowings, conversions, continuations and optional prepayments of Eurodollar Loans and all selections of Interest Periods shall be in such amounts and be made pursuant to such elections so that, (a) after giving effect thereto, the aggregate principal amount of the Eurodollar Loans comprising each Eurodollar Tranche shall be equal to $5,000,000 or a whole multiple of $1,000,000 in excess thereof and (b) no more than ten Eurodollar Tranches shall be outstanding at any one time.

SECTION 3.9 Interest Rates and Payment Dates.

(a) Each Eurodollar Loan shall bear interest for each day during each Interest Period with respect thereto at a rate per annum equal to the Eurodollar Rate determined for such day plus the Applicable Margin for Eurodollar Loans in effect for such day.

(b) Each Base Rate Loan shall bear interest for each day on which it is outstanding at a rate per annum equal to the Base Rate in effect for such day plus the Applicable Margin for Base Rate Loans.

(c) (i) If all or a portion of the principal amount of any Reimbursement Obligation or Loan shall not be paid when due (whether at the stated maturity, by acceleration or otherwise), all outstanding Loans (whether or not overdue) (to the extent legally permitted) shall bear interest at a rate per annum that is equal to in the case of the Loans, the rate that would otherwise be applicable thereto pursuant to the provisions of Section 2 or Section 3, as applicable, plus 2%, and (ii) if all or a portion of any interest payable on any Loan or any facility fee or other amount or fee payable hereunder shall not be paid when due (whether at the stated maturity, by acceleration or otherwise), such overdue amount shall bear interest at a rate per annum equal to the rate then applicable to Base Rate Loans plus 2%, in each case, with respect to clauses (i) and (ii) above, from the date of such non-payment until such amount is paid in full (after as well as before judgment).

(d) Interest shall be payable in arrears on each Interest Payment Date, provided that interest accruing pursuant to paragraph (c) of this Section shall be payable from time to time on demand.

SECTION 3.10 Computation of Interest and Fees.

(a) Interest, fees and commissions payable pursuant hereto shall be calculated on the basis of a 360-day year for the actual days elapsed, except that, with respect to Base Rate Loans on which interest is calculated on the basis of the Prime Rate, the interest thereon shall be calculated on the basis of a 365- (or 366-, as the case may be) day year for the actual days elapsed. The Administrative Agent shall as soon as practicable notify the Borrower and the Lenders of each determination of a Eurodollar Rate. Any change in the interest rate on a Loan resulting from a change in the Base Rate or the Eurocurrency Reserve Requirements shall become effective as of the opening of business on the day on which such change becomes effective. The Administrative Agent shall as soon as practicable notify the Borrower and the Lenders of the effective date and the amount of each such change in interest rate.

(b) Each determination of an interest rate by the Administrative Agent pursuant to any provision of this Agreement shall be conclusive and binding on the Borrower and the Lenders in the absence of manifest error. The Administrative Agent shall, at the request of the Borrower, deliver to the Borrower a statement showing the quotations used by the Administrative Agent in determining any interest rate pursuant to Section 3.9(a).

SECTION 3.11 Inability to Determine Interest Rate. If prior to the first day of any Interest Period:

(a) the Administrative Agent shall have determined (which determination shall be conclusive and binding upon the Borrower) that, by reason of circumstances affecting the relevant market, adequate and reasonable means do not exist for ascertaining the Eurodollar Rate for such Interest Period, or

(b) the Administrative Agent shall have received notice from the Required Lenders that the Eurodollar Rate determined or to be determined for such Interest Period will not adequately and fairly reflect the cost to such Lenders (as conclusively certified by such Lenders) of making or maintaining their affected Loans during such Interest Period, the Administrative Agent shall give telecopy or telephonic notice thereof to the Borrower and the relevant Lenders as soon as practicable thereafter. If such notice is given (x) any Loans that were to have been converted on the first day of such Interest Period to Eurodollar Loans shall be continued as Base Rate Loans and (y) any outstanding Eurodollar Loans shall be converted, on the last day of the then current Interest Period with respect thereto, to Base Rate Loans. Until such notice has been withdrawn by the Administrative Agent, no further Eurodollar Loans shall be continued as such, nor shall the Borrower have the right to convert Loans to Eurodollar Loans.

SECTION 3.12 Pro Rata Treatment and Payments.

(a) Each borrowing by the Borrower from the Lenders hereunder, each payment by the Borrower on account of any facility fee, and any reduction of the Commitments of the Lenders, shall be made pro rata according to the respective Aggregate Exposure Percentages of the Lenders. Each payment in respect of principal or interest in respect of the Loans shall be

applied to the amounts of such obligations owing to the Lenders pro rata according to the respective Aggregate Exposure Percentages of the Lenders.

(b) Each payment to the Administrative Agent of amounts owing to the Issuing Bank pursuant to Section 2.3 shall be promptly transferred by the Administrative Agent to the Issuing Bank.

(c) Each payment (including each prepayment) by the Borrower on account of principal of the Loans shall be accompanied by accrued interest to the date of such payment on the amount paid.

(d) All payments (including prepayments) to be made by the Borrower hereunder, whether on account of principal, interest, fees or otherwise, shall be made without setoff or counterclaim and shall be made prior to 12:00 Noon, New York City time, on the due date thereof to the Administrative Agent, for the account of the Lenders or the Issuing Bank, as the case may be, at the Payment Office, in Dollars and in immediately available funds. Any payment made by the Borrower after 12:00 Noon, New York City time, on any Business Day shall be deemed to have been on the next following Business Day. The Administrative Agent shall distribute such payments to the Lenders or the Issuing Bank, as the case may be, promptly upon receipt in like funds as received. If any payment hereunder (other than payments on the Eurodollar Loans) becomes due and payable on a day other than a Business Day, such payment shall be extended to the next succeeding Business Day. If any payment on a Eurodollar Loan becomes due and payable on a day other than a Business Day, the maturity thereof shall be extended to the next succeeding Business Day unless the result of such extension would be to extend such payment into another calendar month, in which event such payment shall be made on the immediately preceding Business Day. In the case of any extension of any payment of principal pursuant to the preceding two sentences, interest thereon shall be payable at the then applicable rate during such extension.

(e) Unless the Administrative Agent shall have been notified in writing by any Lender prior to a borrowing that such Lender will not make the amount that would constitute its share of such borrowing available to the Administrative Agent, the Administrative Agent may assume that such Lender is making such amount available to the Administrative Agent, and the Administrative Agent may, in reliance upon such assumption, make available to the Borrower a corresponding amount. If such amount is not made available to the Administrative Agent by the required time on the Borrowing Date therefor, such Lender shall pay to the Administrative Agent, on demand, such amount with interest thereon at a rate equal to the daily average Federal Funds Effective Rate for the period until such Lender makes such amount immediately available to the Administrative Agent. A certificate of the Administrative Agent submitted to any Lender with respect to any amounts owing under this paragraph shall be conclusive in the absence of manifest error. If such Lender's share of such borrowing is not made available to the Administrative Agent by such Lender within three Business Days after such Borrowing Date, the Administrative Agent shall also be entitled to recover such amount with interest thereon at the rate per annum applicable to Base Rate Loans, on demand, from the Borrower.

(f) Unless the Administrative Agent shall have been notified in writing by the Borrower prior to the date of any payment due to be made by the Borrower hereunder that the

Borrower will not make such payment to the Administrative Agent, the Administrative Agent may assume that the Borrower is making such payment, and the Administrative Agent may, but shall not be required to, in reliance upon such assumption, make available to the Lenders their respective pro rata shares of a corresponding amount. If such payment is not made to the Administrative Agent by the Borrower within three Business Days after such due date, the Administrative Agent shall be entitled to recover, on demand, from each Lender to which any amount which was made available pursuant to the preceding sentence, such amount with interest thereon at the rate per annum equal to the daily average Federal Funds Effective Rate. Nothing herein shall be deemed to limit the rights of the Administrative Agent or any Lender against the Borrower.

SECTION 3.13 Requirements of Law.

(a) If the adoption of or any change in any Requirement of Law or in the interpretation or application thereof or compliance by the Issuing Bank or any Lender (the term "Lender" as used below in this Section to include the Issuing Bank) with any request or directive (whether or not having the force of law) from any central bank or other Governmental Authority made subsequent to the date hereof:

(i) shall subject any Lender to any tax of any kind whatsoever with respect to this Agreement, any Letter of Credit, any Application for Issuance or any Eurodollar Loan made by it, or change the basis of taxation of payments to such Lender in respect thereof (except for Non-Excluded Taxes covered by Section 3.14 and changes in the rate of tax on the overall net income of such Lender);

(ii) shall impose, modify or hold applicable any reserve, special deposit, compulsory loan or similar requirement against assets held by, deposits or other liabilities in or for the account of, advances, loans or other extensions of credit by, or any other acquisition of funds by, any office of such Lender that is not otherwise included in the determination of the Eurodollar Rate hereunder; or

(iii) shall impose on such Lender any other condition;

and the result of any of the foregoing is to increase the cost to such Lender, by an amount which such Lender deems to be material, of making, converting into, continuing or maintaining Eurodollar Loans, or to reduce any amount receivable hereunder in respect thereof, then, in any such case, the Borrower shall promptly pay such Lender, upon its demand, any additional amounts necessary to compensate such Lender for such increased cost or reduced amount receivable. If any Lender becomes entitled to claim any additional amounts pursuant to this Section, it shall promptly notify the Borrower (with a copy to the Administrative Agent) of the event by reason of which it has become so entitled.

(b) If any Lender shall have determined that the adoption of or any change in any Requirement of Law regarding capital adequacy or in the interpretation or application thereof or compliance by such Lender or any corporation controlling such Lender with any request or directive regarding capital adequacy (whether or not having the force of law) from any Governmental Authority made subsequent to the date hereof shall have the effect of reducing the

rate of return on such Lender's or such corporation's capital as a consequence of its obligations hereunder or under or in respect of any Letter of Credit to a level below that which such Lender or such corporation could have achieved but for such adoption, change or compliance (taking into consideration such Lender's or such corporation's policies with respect to capital adequacy) by an amount deemed by such Lender to be material, then from time to time, after submission by such Lender to the Borrower (with a copy to the Administrative Agent) of a written request therefor, the Borrower shall pay to such Lender such additional amount or amounts as will compensate such Lender or such corporation for such reduction.

(c) A certificate as to any additional amounts payable pursuant to this
Section submitted by any Lender to the Borrower (with a copy to the Administrative Agent) shall be conclusive in the absence of manifest error. The obligations of the Borrower pursuant to this Section shall survive the termination of this Agreement and the payment of the Loans and all other amounts payable hereunder.

SECTION 3.14 Taxes.

(a) All payments made by the Borrower under this Agreement shall be made free and clear of, and without deduction or withholding for or on account of, any present or future income, stamp or other taxes, levies, imposts, duties, charges, fees, deductions or withholdings, now or hereafter imposed, levied, collected, withheld or assessed by any Governmental Authority, excluding net income taxes and franchise taxes (imposed in lieu of net income taxes) imposed on the Administrative Agent or any Lender as a result of a present or former connection between the Administrative Agent or such Lender and the jurisdiction of the Governmental Authority imposing such tax or any political subdivision or taxing authority thereof or therein (other than any such connection arising solely from such Administrative Agent's or such Lender's having executed, delivered or performed its obligations or received a payment under, or enforced, this Agreement or any other Loan Document). If any such non-excluded taxes, levies, imposts, duties, charges, fees, deductions or withholdings ("Non-Excluded Taxes") or any Other Taxes are required to be withheld from any amounts payable to the Administrative Agent or any Lender hereunder, the amounts so payable to the Administrative Agent or such Lender shall be increased to the extent necessary to yield to the Administrative Agent or such Lender (after payment of all Non-Excluded Taxes and Other Taxes) interest or any such other amounts payable hereunder at the rates or in the amounts specified in this Agreement; provided, however, that the Borrower shall not be required to increase any such amounts payable to any Lender with respect to any Non-Excluded Taxes (i) that are attributable to such Lender's failure to comply with the requirements of paragraph (d) or (e) of this Section or (ii) that are United States withholding taxes imposed on amounts payable to such Lender at the time such Lender becomes a party to this Agreement, except to the extent that such Lender's assignor (if any) was entitled, at the time of assignment, to receive additional amounts from the Borrower with respect to such Non-Excluded Taxes pursuant to this paragraph (a).

(b) In addition, the Borrower shall pay any Other Taxes to the relevant Governmental Authority in accordance with applicable law.

(c) Whenever any Non-Excluded Taxes or Other Taxes are payable by the Borrower, as promptly as possible thereafter the Borrower shall send to the Administrative Agent for the

account of the Administrative Agent or the relevant Lender, as the case may be, a certified copy of an original official receipt received by the Borrower showing payment thereof. If the Borrower fails to pay any Non-Excluded Taxes or Other Taxes when due to the appropriate taxing authority or fails to remit to the Administrative Agent the required receipts or other required documentary evidence, the Borrower shall indemnify the Administrative Agent and the Lenders for any incremental taxes, interest or penalties that may become payable by the Administrative Agent or any Lender as a result of any such failure.

(d) Each Lender (or Transferee) that is not a citizen or resident of the United States of America, a corporation, partnership or other entity created or organized in or under the laws of the United States of America (or any jurisdiction thereof), or any estate or trust that is subject to federal income taxation regardless of the source of its income (a "Non-U.S. Lender") shall deliver to the Borrower and the Administrative Agent (or, in the case of a Participant, to the Lender from which the related participation shall have been purchased) two copies of either U.S. Internal Revenue Service Form W-8BEN or Form W-8ECI, or, in the case of a Non-U.S. Lender claiming exemption from U.S. federal withholding tax under Section 871(h) or 881(c) of the Code with respect to payments of "portfolio interest" a statement substantially in the form of Exhibit D and a Form W-8BEN, or any subsequent versions thereof or successors thereto properly completed and duly executed by such Non-U.S. Lender claiming complete exemption from, or a reduced rate of, U.S. federal withholding tax on all payments by the Borrower under this Agreement and the other Loan Documents. Such forms shall be delivered by each Non-U.S. Lender on or before the date it becomes a party to this Agreement (or, in the case of any Participant, on or before the date such Participant purchases the related participation). In addition, each Non-U.S. Lender shall deliver such forms promptly upon the obsolescence or invalidity of any form previously delivered by such Non-U.S. Lender. Each Non-U.S. Lender shall promptly notify the Borrower at any time it determines that it is no longer in a position to provide any previously delivered certificate to the Borrower (or any other form of certification adopted by the U.S. taxing authorities for such purpose). Notwithstanding any other provision of this paragraph, a Non-U.S. Lender shall not be required to deliver any form pursuant to this paragraph that such Non-U.S. Lender is not legally able to deliver.

(e) A Lender that is entitled to an exemption from or reduction of non-U.S. withholding tax under the law of the jurisdiction in which the Borrower is located, or any treaty to which such jurisdiction is a party, with respect to payments under this Agreement shall deliver to the Borrower (with a copy to the Administrative Agent), at the time or times prescribed by applicable law or reasonably requested by the Borrower, such properly completed and executed documentation prescribed by applicable law as will permit such payments to be made without withholding or at a reduced rate, provided that such Lender is legally entitled to complete, execute and deliver such documentation and in such Lender's reasonable judgment such completion, execution or submission would not materially prejudice the legal position of such Lender.

(f) The agreements in this Section shall survive the termination of this Agreement and the payment of the Loans and all other amounts payable hereunder.

SECTION 3.15 Indemnity. The Borrower agrees to indemnify each Lender for, and to hold each Lender harmless from, any loss or expense that such Lender may sustain or

incur as a consequence of (a) default by the Borrower in making a borrowing of, conversion into or continuation of Eurodollar Loans after the Borrower has given a notice requesting the same in accordance with the provisions of this Agreement, (b) default by the Borrower in making any prepayment of or conversion from Eurodollar Loans after the Borrower has given a notice thereof in accordance with the provisions of this Agreement or (c) the making of a prepayment or conversion of Eurodollar Loans on a day that is not the last day of an Interest Period with respect thereto. Such indemnification may include an amount equal to the excess, if any, of (i) the amount of interest that would have accrued on the amount so prepaid, or not so borrowed, converted or continued, for the period from the date of such prepayment or of such failure to borrow, convert or continue to the last day of such Interest Period (or, in the case of a failure to borrow, convert or continue, the Interest Period that would have commenced on the date of such failure) in each case at the applicable rate of interest for such Loans provided for herein (excluding, however, the Applicable Margin included therein, if any) over (ii) the amount of interest (as reasonably determined by such Lender) that would have accrued to such Lender on such amount by placing such amount on deposit for a comparable period with leading banks in the interbank eurodollar market. A certificate as to any amounts payable pursuant to this Section submitted to the Borrower by any Lender shall be conclusive in the absence of manifest error. This covenant shall survive the termination of this Agreement and the payment of the Loans and all other amounts payable hereunder.

SECTION 3.16 Illegality. Notwithstanding any other provision herein, if the adoption of or any change in any Requirement of Law or in the interpretation or application thereof shall make it unlawful for any Lender to make or maintain Eurodollar Loans as contemplated by this Agreement, (a) the commitment of such Lender hereunder to make Eurodollar Loans, continue Eurodollar Loans as such and convert Base Rate Loans to Eurodollar Loans shall forthwith be canceled and (b) such Lender's Loans then outstanding as Eurodollar Loans, if any, shall be converted automatically to Base Rate Loans on the respective last days of the then current Interest Periods with respect to such Loans or within such earlier period as required by law. If any such conversion of a Eurodollar Loan occurs on a day which is not the last day of the then current Interest Period with respect thereto, the Borrower shall pay to such Lender such amounts, if any, as may be required pursuant to Section 3.15.

SECTION 3.17 Change of Lending Office. Each of the Issuing Bank and the Lenders (the term "Lender" as used below in this Section to include the Issuing Bank) agrees that, upon the occurrence of any event giving rise to the operation of Section 3.13, 3.14(a) or 3.16 with respect to such Lender, it will, if requested by the Borrower, use reasonable efforts (subject to overall policy considerations of such Lender) to designate another lending office for any Loans or Letters of Credit affected by such event with the object of avoiding the consequences of such event; provided, that such designation is made on terms that, in the sole judgment of such Lender, cause such Lender and its lending office(s) to suffer no economic, legal or regulatory disadvantage, and provided, further, that nothing in this Section shall affect or postpone any of the obligations of any Borrower or the rights of any Lender pursuant to Section 3.13, 3.14(a) or 3.16.

SECTION 3.18 Replacement of Lenders. The Borrower shall be permitted to replace any Lender that (a) requests reimbursement for amounts owing pursuant to
Section 3.13 or 3.14(a) or (b) defaults in its obligation to make Loans hereunder, with a replacement financial institution; provided that (i) such replacement does not conflict with any Requirement of Law, (ii) except in the case of a replacement as a result of a default described in clause (b) above, no Event of Default shall have occurred and be continuing at the time of such replacement, (iii) prior to any such replacement, such Lender shall have taken no action under Section 3.17 so as to eliminate the continued need for payment of amounts owing pursuant to Section 3.13 or 3.14(a), (iv) the replacement financial institution shall purchase, at par, all Loans and other amounts owing to such replaced Lender on or prior to the date of replacement, (v) the replacement financial institution, if not already a Lender, shall be reasonably satisfactory to the Administrative Agent, (vi) the replaced Lender shall be obligated to make such replacement in accordance with the provisions of Section 9.6 (provided that the Borrower shall be obligated to pay the registration and processing fee referred to therein), (viii) until such time as such replacement shall be consummated, the Borrower shall pay all additional amounts (if any) required pursuant to Section 3.13 or 3.14(a), as the case may be, and (ix) any such replacement shall not be deemed to be a waiver of any rights that the Borrower, the Administrative Agent or any other Lender shall have against the replaced Lender.

SECTION 3.19 Extension of Termination Dates

(a) So long as no Default or Event of Default shall have occurred and is continuing, any Termination Date, and concomitantly the Commitments of the relevant Lenders, may be extended for successive 364-day periods expiring on the date which is 364 days from the then scheduled Termination Date. In order to request such extension, the Borrower will deliver to the Administrative Agent not more than sixty (60) days nor less than forty-five (45) days prior to the then scheduled Termination Date a written request that such Termination Date be extended for 364 days from the then scheduled Termination Date. The Administrative Agent shall then promptly notify each relevant Lender of such request, and each relevant Lender shall notify the Administrative Agent in writing no later than ten Business Days after receipt by such Lenders of the relevant request for an extension from the Borrower, pursuant to this Section 3.19, whether such Lender, in the exercise of its sole discretion, will extend the Termination Date for such 364-day period. Any relevant Lender which shall not timely notify the Administrative Agent whether it will extend such Termination Date shall be deemed not to have agreed to the extension. No Lender shall have any obligation whatsoever to agree to extend any Termination Date. Any agreement to extend any Termination Date by any Lender shall be irrevocable, except to the extent revocable by the Borrower as provided in Section 3.19(c)(C)(iii).

(b) If all the relevant Lenders notify the Administrative Agent pursuant to the foregoing provisions of this Section 3.19 of their agreement to extend the relevant Termination Date (such Lenders agreeing to extend such Termination Date, the "Accepting Lenders"), then the Administrative Agent shall so notify each relevant Lender and the Borrower, and such extension shall become effective without further action by any party hereto.

(c) If Lenders constituting at least the Required Lenders approve the extension of the relevant Termination Date and if one or more of the relevant Lenders shall notify, or be deemed to have notified, the Administrative Agent that they will not extend the then scheduled

Termination Date (such Lenders, the "Declining Lenders"), then (A) the Administrative Agent shall promptly so notify the Borrower and the Accepting Lenders, (B) the Accepting Lenders shall, upon the Borrower's election to extend the then scheduled Termination Date in accordance with clause (C)(i) or (C)(ii) below, extend the then scheduled Termination Date and (C) the Borrower shall, pursuant to a notice delivered to the Administrative Agent, the Accepting Lenders and the Declining Lenders, no later than the tenth day following the date by which each Lender is required, pursuant to this Section 3.19, to approve or disapprove the requested extension, either:

(i) elect to extend such Termination Date with respect to the Accepting Lenders and direct the Declining Lenders to terminate their Commitments, which termination shall become effective on the date which would have been the Termination Date except for the operation of this Section 3.19. On such date, (x) the Borrower shall deliver a notice of the effectiveness of such termination to the Declining Lenders with a copy to the Administrative Agent,
(y) the Borrower shall pay in full in immediately available funds all Obligations owing to the Declining Lenders and (z) upon the occurrence of the events set forth in clauses (x) and (y), the Declining Lenders shall each cease to be a Lender hereunder for all purposes and the Declining Lenders shall no longer have any obligations hereunder; provided, however, such Person shall be obligated to make or entitled to receive payments pursuant to Sections 3.13, 3.15, 8.7 and 9.5 (but only to the extent the event giving rise to such payment occurred prior to the time at which the events set forth in clauses (x) and (y) shall have occurred) as if it were a Lender, and the Administrative Agent shall promptly notify the Accepting Lenders and the Borrower of any new Commitments and any new Termination Date; or

(ii) elect to extend such Termination Date with respect to the Accepting Lenders and, prior to or no later than the then scheduled Termination Date, (a) the Borrower shall replace the Declining Lenders with one or more lenders reasonably acceptable to the Administrative Agent (such lenders, the "Replacement Lenders") or with any one or more of the Accepting Lenders, if any, which have agreed with the Borrower to increase their respective Commitments (the "Increasing Accepting Lenders") or to the extent the Borrower is not able to replace all Commitments of any Declining Lender, direct such Declining Lenders to terminate any such Commitments not being replaced as provided in clause (i) above and (b) the Borrower shall pay in full in immediately available funds all Obligations owed by the Borrower to the Declining Lenders which are not being replaced; provided that (x) the Replacement Lenders and Increasing Accepting Lenders shall purchase, and the Declining Lenders being replaced shall sell, the interest of the Declining Lenders being replaced and their rights hereunder without recourse or expense to, or warranty (except warranty of ownership which is free and clear of any adverse claims) by, such Declining Lenders being replaced for a purchase price equal to the aggregate outstanding principal amount of Obligations payable to such Declining Lenders plus any accrued but unpaid interest on such Obligations and accrued but unpaid fees in respect of such Declining Lenders' Loans and Commitments hereunder, and (y) all Obligations of the Borrower owing under or in connection with this Agreement with respect to the Declining Lenders being replaced (including, without limitation, such increased costs, breakage fees payable under Sections 3.13 and 3.14 and all other costs and expenses payable to each such Declining Lender) shall be paid in full in immediately available funds to such Declining Lenders concurrently with such replacement, and (z) upon the payment of such amounts referred to in clauses (x) and (y), the Replacement Lenders shall each constitute a Lender hereunder and the Declining Lenders being

so replaced shall no longer constitute a Lender or Issuing Bank (if applicable) and shall no longer have any obligations hereunder. However, such Person shall be obligated to make or entitled to receive payments pursuant to Sections 3.13, 3.15, 8.7 and 9.5 (but only to the extent the event giving rise to such payment occurred prior to the time at which the events set forth in clauses (x) and (y) shall have occurred) as if it were a Lender; or

(iii) elect to revoke and cancel such extension request by giving notice of such revocation and cancellation to the Administrative Agent (which shall promptly notify the relevant Lenders thereof) no later than the tenth day following the date by which each relevant Lender is required, pursuant to this
Section 3.19, to approve or disapprove the requested extension of such Termination Date, and concomitantly the Commitments of the relevant Lenders. If the Borrower fails to timely provide the election notice referred to in this clause (C), the Borrower shall be deemed to have revoked and canceled such extension request and to have elected not to extend the relevant Termination Date and the Commitments of the relevant Lenders, and, on the then scheduled Termination Date, the Borrower shall repay in full all Obligations under the Loan Documents.

(d) Notwithstanding any of the foregoing, in the event that the Issuing Bank is a Declining Lender, the Borrower shall implement arrangements satisfactory in all respects to the Issuing Bank with respect to all Letters of Credit that would remain outstanding after the Issuing Bank ceases to be a Lender and Issuing Bank under this Agreement.

(e) On and after the effectiveness of any extension under this
Section 3.19, in no event shall (i) the aggregate stated amount of all outstanding Tranche A Letters of Credit exceed the aggregate Tranche A Commitments and (ii) the aggregate stated amount of all outstanding Tranche B Letters of Credit exceed the aggregate Tranche B L/C Limit.

ARTICLE IV

REPRESENTATIONS AND WARRANTIES

To induce the Administrative Agent, the Issuing Bank and the Lenders to enter into this Agreement, to issue the Letters of Credit and to make the Loans, the Borrower hereby represents and warrants to the Administrative Agent, the Issuing Bank and each Lender that:

SECTION 4.1 Organization; Powers; Ownership of Property. The Borrower and each of its Subsidiaries (other than Unrestricted Subsidiaries) (a) is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation, except, with respect to such Subsidiaries, where the failure to be validly existing or in good standing is not reasonably likely to result in a Material Adverse Effect, (b) has all requisite power and authority to own its property and assets and to carry on its business as now conducted and as proposed to be conducted, (c) is qualified to do business in every jurisdiction where such qualification is required, except where the failure so to qualify is not reasonably likely to result in a Material Adverse Effect, (d) as to the Borrower only, has the power and authority to execute, deliver and perform its obligations under this Agreement and the other Loan Documents, and (e) owns and has good and marketable title to all of its properties and assets, subject to no Liens other than those permitted by Section 6.11 hereof, except where the failure to own or to have good and

marketable title to such property or asset is not reasonably likely to result in a Material Adverse Effect.

SECTION 4.2 Authorization. The execution, delivery and performance by the Borrower of this Agreement and the other Loan Documents each (a) have been duly authorized by all requisite corporate action on the part of the Borrower, and (b) will not (i) violate (A) any provision of any law, statute, rule or regulation to which the Borrower is subject, (B) the articles of incorporation or by-laws of the Borrower, (C) any order of any Governmental Authority to which the Borrower is subject, or (D) any material provision of any indenture, agreement or other instrument to which the Borrower is a party or by which it or any of its property is or may be bound, which such violation is reasonably likely to result in a Material Adverse Effect, (ii) constitute (alone or with notice or lapse of time or both) a default under any such indenture, agreement or other instrument, which such default is reasonably likely to result in a Material Adverse Effect or (iii) result in the creation or imposition of any Lien upon any property or assets of the Borrower, which such Lien is reasonably likely to result in a Material Adverse Effect.

SECTION 4.3 Enforceability. This Agreement and the other Loan Documents each constitutes a legal, valid and binding obligation of the Borrower enforceable in accordance with its terms except to the extent that enforcement may be limited by bankruptcy, insolvency or similar laws affecting the enforcement of creditors' rights generally.

SECTION 4.4 Financial Statements.

(a) The consolidated balance sheet of the Borrower and its Subsidiaries as of December 31, 1999 and December 31, 2000, reported on by an independent public accountant of nationally recognized standing, and the related consolidated statements of income, retained earnings and cash flows for the fiscal periods then ended, copies of which have been delivered to the Administrative Agent, fairly presented in conformity with GAAP, the consolidated financial position of the Borrower and its Subsidiaries as of such dates and their consolidated results of operations and cash flows for such periods ending on such dates.

(b) The assumptions used in preparing the Projections were made in good faith and are reasonable as of the date of such Projections and as of the date hereof.

(c) Since December 31, 2000, there has been no development or condition that has had, or could reasonably be expected to result in, a Material Adverse Effect.

SECTION 4.5 Litigation. Except as set forth on Schedule 4.5, there is no investigation, action, suit or proceeding pending against, or to the Actual Knowledge of the Borrower threatened against or affecting, the Borrower or any of its Subsidiaries (other than Unrestricted Subsidiaries) before any court or arbitrator or any governmental body, agency or official in which an adverse decision is reasonably likely to result in a Material Adverse Effect or call into question the enforceability of this Agreement or the other Loan Documents.

SECTION 4.6 Federal Reserve Regulations.

(a) Neither the Borrower nor any of its Subsidiaries is engaged principally, or as one of its important activities, in the business of extending credit for the purpose of "buying" or "carrying" Margin Stock (within the respective meanings of each of the quoted terms under Regulation U). No part of the proceeds of any Loans, and no other extensions of credit hereunder, will be used for "buying" or "carrying" Margin Stock (within the respective meanings of such quoted terms under Regulation U) or for any purpose that violates the provisions of the regulations of the Board. If requested by any Lender or the Administrative Agent, the Borrower will furnish to the Administrative Agent and each Lender a statement to the foregoing effect in conformity with the requirements of FR Form G-3 or FR Form U-1, as applicable, referred to in Regulation U.

(b) Not more than 25 % of the value of the assets of the Borrower is represented by Margin Stock.

SECTION 4.7 Investment Company Act; Public Utility Holding Company Act.

(a) Neither the Borrower nor any of its Subsidiaries is an "investment company" as defined in, or subject to regulation under, the Investment Company Act of 1940.

(b) The Borrower is not a "holding company" but is a "subsidiary company" and an "affiliate" of a "holding company", PG&E Corp., that is exempt from all provisions, except Section 9(a)(2), of the Public Utility Holding Company Act of 1935, as amended, and the execution, delivery and performance by the Borrower of this Agreement and the other Loan Documents and its obligations hereunder and thereunder do not violate any provision of such Act or any rule or regulation thereunder.

SECTION 4.8 No Material Misstatements. The reports, financial statements and other written information furnished by or on behalf of the Borrower to the Administrative Agent, the Issuing Bank or any Lender pursuant to or in connection with this Agreement and the other Loan Documents do not contain, when taken as a whole, any untrue statement of a material fact and do not omit, when taken as a whole, to state any fact necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading in any material respect.

SECTION 4.9 Taxes. The Borrower has filed or caused to be filed all Federal and material state and local tax returns which to its Actual Knowledge are required to be filed by it, and has paid or caused to be paid all material taxes shown to be due and payable on such returns or on any assessments received by it, other than any taxes or assessments the validity of which is being contested in good faith by appropriate proceedings and with respect to which appropriate accounting reserves have to the extent required by GAAP been set aside. Each Subsidiary of the Borrower (other than any Unrestricted Subsidiary) has filed or caused to be filed all Federal and material state and local tax returns which to the Actual Knowledge of the Borrower or such Subsidiary are required to be filed by such Subsidiary, and has paid or caused to be paid all material taxes shown to be due and payable on such returns or on any assessments received by it, other than the taxes the failure of which to pay or file a return with respect thereto is not reasonably likely to result in a Material Adverse Effect.

SECTION 4.10 Employee Benefit Plans. With respect to each Plan, the Borrower and its ERISA Affiliates are in compliance in all material respects with the applicable provisions of ERISA and the Code and the final regulations and published interpretations thereunder. No ERISA Event has occurred that alone or together with any other ERISA Event has resulted or is reasonably likely to result in a Material Adverse Effect.

SECTION 4.11 Governmental Approval; Compliance with Law and Contracts. The Borrower and each of its Subsidiaries (other than Unrestricted Subsidiaries) is in compliance with (a) and has obtained each Governmental Approval applicable to it in respect of this Agreement and the other Loan Documents, the conduct of its business and the ownership of its property, each of which (i) is in full force and effect, (ii) is sufficient for its purpose without any material restraint or adverse condition and (iii) is not subject to any waiting period, further action on the part of any Governmental Authority or other Person, or stay or injunction, (b) all applicable laws relating to its business and (c) each indenture, agreement or other instrument to which it is a party or by which it or any of its property is or may be bound that is material to the conduct of its business, except in each such case for noncompliances which, and Governmental Approvals the failure to possess which, are not, singly or in the aggregate, reasonably likely to result in a Material Adverse Effect.

SECTION 4.12 Environmental Matters. Except as set forth in Schedule 4.12 or as set forth in or contemplated by the financial statements or other reports of the type referred to in Section 4.4 hereof and which have been delivered to the Administrative Agent on or prior to the date hereof, the Borrower and each of its Subsidiaries (other than Unrestricted Subsidiaries) have complied in all material respects with all Federal, state, local and other statutes, ordinances, orders, judgments, rulings and regulations relating to environmental pollution or to environmental or nuclear regulation or control, except to the extent that failure to so comply is not reasonably likely to result in a Material Adverse Effect. Except as set forth in or contemplated by such financial statements or other reports, neither the Borrower nor any of its Subsidiaries (other than Unrestricted Subsidiaries) has received notice of any material failure so to comply, except where such failure is not reasonably likely to result in a Material Adverse Effect. Except as set forth in or contemplated by such financial statements or other reports, no facilities of the Borrower or any of its Subsidiaries (other than Unrestricted Subsidiaries) are used to manage any hazardous wastes, hazardous substances, hazardous materials, toxic substances, toxic pollutants or substances similarly denominated, as those terms or similar terms are used in the Resource Conservation and Recovery Act, the Comprehensive Environmental Response Compensation and Liability Act, the Hazardous Materials Transportation Act, the Toxic Substance Control Act, the Clean Air Act, the Clean Water Act or any other applicable law relating to environmental pollution, or any nuclear fuel or other radioactive materials, in violation of any law or any regulations promulgated pursuant thereto, except to the extent that such violations, individually or in the aggregate, are not reasonably likely to result in a Material Adverse Effect. Except as set forth in or contemplated by such financial statements or other reports, the Borrower is aware of no events, conditions or circumstances involving environmental pollution or contamination that are reasonably likely to result in a Material Adverse Effect.

SECTION 4.13 Ranking. Under applicable laws in force on the date hereof, the claims and rights of the Lenders under this Agreement and the other Loan Documents in respect

of the Obligations shall not be subordinate to, and shall rank at least pari passu in all respects with, the claims and rights of any other holders of unsecured Indebtedness of the Borrower.

SECTION 4.14 Unrestricted Subsidiaries. All Unrestricted Subsidiaries designated as such on the date hereof are identified on Schedule 4.14.

SECTION 4.15 Use of Letters of Credit. The Letters of Credit shall not be used as payment assurance in connection with any Equity Funding Arrangement of the Borrower or any of its Subsidiaries.

SECTION 4.16 CPUC. Neither the Borrower nor any of its Subsidiaries are

regulated by the California Public Utilities Commission.

SECTION 4.17 Separateness from PG&E.

(a) The Borrower has operated as a business entity separate and distinct in all relevant respects from PG&E Corp. and PG&E such that the Borrower believes there exists no reasonable basis for a substantive consolidation of NEG LLC or any of its Subsidiaries with either PG&E Corp. or PG&E in the event of a bankruptcy proceeding with respect to either of such Persons.

(b) Any transfer of assets or funds from PG&E Corp. or PG&E (either directly or through PG&E Corp.) to the Borrower during the period from the date of the Borrower's incorporation on December 18, 1998 until the date hereof (i) to the Borrower's knowledge, after due inquiry, was made at a time when the transferor was solvent and was able to pay its reasonably anticipated liabilities as they became due, (ii) was received by the Borrower in good faith and (iii) to the Borrower's knowledge, was made without intent to hinder, delay or defraud creditors of the transferor.

ARTICLE V

CONDITIONS PRECEDENT

SECTION 5.1 Conditions to Initial Extension of Credit. The obligations of the Issuing Bank to issue the initial Letter of Credit requested by Borrower pursuant to Section 2.1 of this Agreement and of the Lenders to make the initial Loans requested by Borrower to be made pursuant to Section 3.1(a) and/or 3.1(b) of this Agreement are subject to the satisfaction of the following conditions precedent:

(a) Loan Documents. The Administrative Agent shall have received (i) this Agreement, executed and delivered by the Agents, the Borrower and each Person listed on Schedule 1.1, (ii) an Application for Issuance, if applicable, executed by the Borrower and (iii) the Letter Agreement, executed by NEG LLC.

(b) Financial Statements. The Administrative Agent shall have received (i) audited consolidated financial statements of the Borrower for the 1999 and 2000 fiscal years, (ii) unaudited unconsolidated financial statements of the Borrower for the 2000 fiscal year and (iii) unaudited interim consolidated and unconsolidated financial statements of the Borrower, in each

case, for each quarterly period ended subsequent to the date of the latest applicable financial statements delivered pursuant to clauses (i) and (ii) of this paragraph as to which such financial statements are available; and such financial statements shall not, in the reasonable judgment of the Administrative Agent, reflect any material adverse change in the consolidated financial condition of the Borrower, as reflected in the financial statements or Projections previously disclosed to the Administrative Agent.

(c) Approvals. All Governmental Approvals and third party approvals necessary in connection with the financing contemplated hereby shall have been obtained and be in full force and effect.

(d) Related Agreements. The Administrative Agent shall have received (in a form reasonably satisfactory to the Administrative Agent), true and correct copies, certified as to authenticity by the Borrower, of such other documents or instruments as may be reasonably requested by the Administrative Agent, including, without limitation, a copy of any debt instrument, security agreement or other material contract to which Borrower may be a party. The Administrative Agent shall be reasonably satisfied that no such instrument, agreement or contract shall be in default immediately prior to or after giving effect to this Agreement and the other Loan Documents, and the Borrower shall so certify in writing.

(e) Fees. The Lenders and the Administrative Agent shall have received

all fees required to be paid, and all expenses for which invoices have been presented (including reasonable fees, disbursements and other charges of counsel to the Administrative Agents), on or before the Closing Date. All such amounts may be paid with proceeds of Loans made on the Closing Date and may be reflected in the funding instructions given by the Borrower to the Administrative Agent on or before the Closing Date.

(f) Closing Certificate. The Administrative Agent shall have received a certificate of the Borrower, dated the Closing Date, substantially in the form of Exhibit A, with appropriate insertions and attachments.

(g) Legal Opinions. The Administrative Agent shall have received the following executed legal opinions:

(i) the legal opinion of Hunton & Williams, counsel to Borrower, substantially in the form of Exhibit C-1;

(ii) the legal opinion of Hunton & Williams, substantially in the form of Exhibit C-2;

(iii) the legal opinion of Stephen A. Herman, general counsel of the Borrower, substantially in the form of Exhibit C-3.

(h) $1.1 Billion PG&E Gen Credit Agreement. The Administrative Agent shall have received confirmation from the Borrower that the $1.1 Billion PG&E Gen Credit Agreement has been terminated and all loans, borrowings and other amounts due thereunder have been paid.

(i) $550M Credit Facility. The $550M Credit Facility shall have been replaced by the Agreement (it being understood and agreed that all letters of credit outstanding under the

$550M Credit Facility on the Closing Date shall constitute Tranche A Letters of Credit hereunder).

SECTION 5.2 Conditions to Issuance of Each Letter of Credit under Section 2.1 and each Loan under Section 3.1(a) and 3.1(b). The obligations of the Issuing Bank to issue any Letter of Credit requested to be issued by it hereunder on any date, and the Lenders to make a Loan under Section 3.1(a) and/or 3.1(b) hereof on any date is subject to the satisfaction of the following conditions precedent:

(a) Representations and Warranties. Each of the representations and warranties made by the Borrower in or pursuant to the Loan Documents shall be true and correct on and as of such date as if made on and as of such date.

(b) No Default. No Default or Event of Default shall have occurred and be continuing on such date or after giving effect to the extensions of credit requested to be made on such date.

Each request by the Borrower for issuance of a Letter of Credit under Section 2.1 hereof or a Loan under Section 3.1(a) and/or 3.1(b) shall constitute a representation and warranty by the Borrower as of the date of such issuance that the conditions contained in this Section 5.2 have been satisfied.

ARTICLE VI

COVENANTS

The Borrower hereby agrees that, so long as the Commitments remain in effect, any Letter of Credit remains outstanding or any Loan or other amount is owing to the Issuing Bank, any Lender or the Administrative Agent hereunder, the Borrower shall and shall cause each of its Subsidiaries to comply with each of the following covenants:

SECTION 6.1 Maintenance of Ownership. The Borrower shall continue (x) to own at least 50% of the equity ownership interests of, and (y) control the management and operations of, each of its Restricted Subsidiaries (except for certain Restricted Subsidiaries listed on Schedule 6.1); provided that (I) the Borrower will in any event continue to own at least 80% of the equity ownership interests of PG&E Gen, ET Holdings and GTN; provided, further, that the Borrower may wind up, dissolve or liquidate any Restricted Subsidiary (other than PG&E Gen, ET Holdings and GTN) without complying with the foregoing, so long as assets thereof are transferred or otherwise conveyed to another Restricted Subsidiary or the Borrower.

SECTION 6.2 Existence. The Borrower will, and will cause each of its Subsidiaries (other than Unrestricted Subsidiaries) to, do or cause to be done all things necessary to preserve and keep in full force and effect its legal existence and all rights, licenses, permits, franchises and authorizations necessary or desirable in the normal conduct of its business, except as otherwise permitted pursuant to Sections 6.1 (including Schedule 6.1) and 6.9, and in the case of any such Subsidiaries, except as such failure to so preserve or to keep its legal existence and

such rights, licenses, permits, franchises or authorizations in full force and effect is not reasonably likely to result in a Material Adverse Effect.

SECTION 6.3 Compliance with Law; Business and Properties. The Borrower will, and will cause each of its Restricted Subsidiaries to, comply with all applicable material laws, rules, regulations and orders of any Governmental Authority, whether now in effect or hereafter enacted, except where the validity or applicability of such laws, rules, regulations or orders is being contested by appropriate proceedings in good faith or where such non-compliance is not reasonably likely to result in a Material Adverse Effect; comply with the terms of each indenture, agreement or other instrument to which it is a party and enforce all of its rights thereunder, except to the extent that noncompliance or failure to enforce is not reasonably likely to cause a Material Adverse Effect; and at all times maintain and preserve all property material to the conduct of its business and keep such property in good repair, working order and condition and from time to time make, or cause to be made, all needful and proper repairs, renewals, additions, improvements and replacements thereto necessary in order that the business carried on in connection therewith may be properly conducted at all times, except where the failure to take any such actions is not reasonably likely to result in a Material Adverse Effect.

SECTION 6.4 Financial Statements, Reports, Etc. The Borrower will furnish to the Administrative Agent, which will promptly forward the same to each Lender:

(a) as soon as available and in any event within 120 days after the end of each fiscal year of the Borrower, an audited consolidated balance sheet of the Borrower and its Subsidiaries as of the end of such fiscal year and the related audited consolidated statements of income, retained earnings and cash flows for such fiscal year, setting forth in each case in comparative form the figures for the previous fiscal year, to the extent available, all reported on by an independent public accountant of nationally recognized standing;

(b) as soon as available and in any event within 45 days after the end of each of the first three quarters of each fiscal year of the Borrower a consolidated balance sheet of the Borrower and its Subsidiaries as of the end of such quarter and the related consolidated statements of income for such quarter and for the portion of the Borrower's fiscal year ended at the end of such quarter, and the related consolidated statement of cash flows for such quarter and for the portion of the Borrower's fiscal year ended at the end of such quarter, in each case setting forth comparative figures for the previous dates and periods, to the extent available, all certified (subject to normal year-end adjustments) as to fairness of presentation, GAAP and consistency by a Financial Officer of the Borrower;

(c) simultaneously with any delivery of each set of financial statements referred to in paragraphs (a) and (b) above, (i) an unconsolidated balance sheet of the Borrower and the related unconsolidated statements of income, retained earnings and cash flows as of the same date and for the same periods applicable to the statements delivered pursuant to paragraph (a) or (b) above, as applicable, all certified (subject to normal year-end adjustments in the case of quarterly statements) as to fairness of presentation by a Financial Officer of the Borrower and (ii) a certificate of a Financial Officer of the Borrower (A) setting forth in reasonable detail the calculations required to establish whether the Borrower was in compliance with the requirements of Section 6.15 on the date of such financial statements, and schedules setting forth all

Indebtedness described in Section 6.12(o) that was incurred during the applicable period and (B) stating whether any Default or Event of Default exists on the date of such certificate and, if any Default or Event of Default then exists, setting forth the details thereof and the action which the Borrower is taking or proposes to take with respect thereto;

(d) simultaneously with the delivery of each set of financial statements referred to in paragraph (a) above, a statement of the firm of independent public accountants which reported on such statements confirming the calculations set forth in the Financial Officer's certificate delivered simultaneously therewith pursuant to subsection (c) above;

(e) promptly upon a Responsible Officer of the Borrower obtaining Actual Knowledge of the occurrence of any Default or Event of Default, a certificate of a Financial Officer of the Borrower setting forth the details thereof and the action which the Borrower is taking or proposes to take with respect thereto;

(f) on or prior to the date of incurrence of any Indebtedness pursuant to
Section 6.12(c) or (l) or the date of any Distribution pursuant to Section 6.14,
(i) a certificate of a Financial Officer of the Borrower setting forth in reasonable detail the calculations demonstrating compliance by the Borrower with the applicable financial tests, together with the pro forma calculations referred to in the applicable Section, and copies of all financial statements and other supporting documents and reports, if any, upon which the Borrower relied in making such calculations, and (ii) with respect to Section 6.12(c) and
(l) only, written evidence of the confirmation of the rating agency ratings, to the extent such confirmation is required under Section 6.12 (c) or (l), as the case may be;

(g) (i) on or prior to the date hereof, copies of the PG&E Gen Credit Agreement, ET Credit Agreements, GTN Credit Agreements, USGenNE Credit Agreements, NEG Guarantees and NEG Indenture in each case accompanied by a certificate of a Responsible Officer of the Borrower stating that such copies are true and complete, and (ii) promptly upon any refinancing of the loans under any such facility, copies of the refinancing documents, accompanied by a certificate of a Responsible Officer of the Borrower stating that such copies are true and complete;

(h) promptly upon a Responsible Officer of the Borrower obtaining Actual Knowledge of any change in the credit rating of the Borrower by S&P or Moody's, a notice thereof.

SECTION 6.5 Insurance. The Borrower will, and will cause each of its Subsidiaries (other than Unrestricted Subsidiaries) to, maintain such insurance or self insurance, to such extent and against such risks, including fire and other risks insured against by extended coverage, as is customary with companies similarly situated and in the same or similar businesses except, in the case of any such Subsidiaries, where such failure to so maintain is not reasonably likely to result in a Material Adverse Effect.

SECTION 6.6 Taxes, Etc. The Borrower will, and will cause each of its Subsidiaries (other than Unrestricted Subsidiaries) to, pay and discharge promptly when due all material taxes, assessments and governmental charges imposed upon it or upon its income or profits or in respect of its property, in each case before the same shall become delinquent or in default and before penalties accrue thereon, unless and to the extent that the same are being contested in good faith by appropriate proceedings and adequate reserves with respect thereto shall, to the extent required by GAAP, have been set aside except, in the case of any such Subsidiaries, where such failure to so pay or discharge is not reasonably likely to result in a Material Adverse Effect.

SECTION 6.7 Maintaining Records; Access to Properties and Inspections. The Borrower will, and will cause each of its Restricted Subsidiaries to, maintain financial records in accordance with GAAP and, upon reasonable notice and at reasonable times, permit authorized representatives designated by the Administrative Agent to visit and inspect its properties, books and records and to discuss its affairs, finances and condition with its officers.

SECTION 6.8 Risk Management Procedures. The Borrower will, and will cause each of its Restricted Subsidiaries to, maintain in effect prudent risk management procedures with respect to Trading Arrangements and Swaps.

SECTION 6.9 Merger. The Borrower will not consolidate or merge with or into any Person, or sell, lease or otherwise transfer, in a single transaction or in a series of transactions, all or substantially all of its assets to any Person or Persons, unless (i) the surviving Person or transferee is formed under the laws of a State of the United States of America and assumes or is responsible by operation of law for all the Obligations and (ii) no Default, Event of Default or Downgrade Event shall have occurred or be continuing at the time of or after giving effect to such consolidation or merger or transfer.

SECTION 6.10 Investments. The Borrower will not make any Investment, or permit any of its Restricted Subsidiaries to make any Investment, except:

(a) Investments in any Restricted Subsidiary, Investment Vehicle or Asset Company (or any Person that will become a Restricted Subsidiary, Investment Vehicle or Asset Company, as the case may be, upon the making of such Investment); or

(b) Investments (not otherwise permitted under this Section 6.10) existing on the date of execution of this Agreement which are identified on Schedule 6.10 or Schedule 6.13; or

(c) Investments permitted to be incurred as Indebtedness under Section 6.12; or

(d) (i) Investments made by any Restricted Subsidiary in the Borrower or any Restricted Subsidiary in connection with the Borrower's cash management program or (ii) Investments in Cash Equivalents; or

(e) Investments constituting "Equity Funding Arrangements" permitted hereunder; or

(f) Investments otherwise made by the Borrower and its Restricted Subsidiaries in the ordinary course of business as conducted by the Borrower or its Restricted Subsidiaries or by

other Persons in the energy trading, energy services, power generation, electric transmission or gas transmission and storage businesses (including technologies related to such businesses); or

(g) Investments in connection with obligations in support of Trading Arrangements; or

(h) Investments in any Unrestricted Subsidiary with amounts which would otherwise be available for distribution in accordance with Section 6.14.

SECTION 6.11 Liens. The Borrower will not create or assume or permit to exist any Lien, or permit any Restricted Subsidiary, Investment Vehicle or Asset Company to, create or assume or permit to exist any Lien, in respect of any of its property or assets of any kind (real or personal, tangible or intangible), except:

(a) Liens granted pursuant to Lease Obligations described in clause (i) of the definition of "Lease Obligations" and permitted by Section 6.12; or

(b) Liens on cash collateral securing Equity Funding Arrangements, Credit Support Arrangements, Investments or Indebtedness permitted hereunder; or

(c) Liens existing on the assets of any Person at the time such Person becomes a Subsidiary of the Borrower; or

(d) Liens on the equity or ownership interests of any Asset Company or any Investment Vehicle which owns such Asset Company and Liens on any Equity Funding Arrangements securing the applicable Project Financing Facility; or

(e) Liens on any of the assets of any Asset Company or Investment Vehicle securing or in connection with the applicable Project Financing Facility; or

(f) Liens on any asset of the Borrower or any Restricted Subsidiary incurred or assumed for the purpose of financing all or any part of the cost of acquiring, constructing or improving such asset, provided that such Lien attaches contemporaneously with, or within 12 months of, the purchase, construction or improvement of such asset; or

(g) Other Liens (not otherwise permitted under this Section 6.11) existing as of the date of this Credit Agreement and identified on Schedule 6.11; or

(h) Permitted Encumbrances; or

(i) without limiting the ability to incur Liens under the other subsections of this Section 6.11, extensions or renewals of any Lien otherwise permitted to be incurred under this Section 6.11 securing Indebtedness in an amount not exceeding the principal amount of, and accrued interest on, the Indebtedness secured by such Lien as so extended or renewed at the time of such extension or renewal; provided that such Lien shall apply only to the same property theretofore subject to the same and fixed improvements constructed thereon.

SECTION 6.12 Indebtedness. The Borrower will not incur, create, assume or permit to exist Indebtedness, or permit any Restricted Subsidiary, Investment Vehicle or Asset Company to, incur, create, assume or permit to exist Indebtedness, except:

(a) Indebtedness under (i) this Agreement, the PG&E Gen Credit Agreement, the USGenNE Credit Agreement, the GTN Credit Agreements and the ET Credit Agreements (the "Refinanceable Facilities"), (ii) the NEG Indenture and the NEG Guarantees, and (iii) other credit facilities entered into by the Borrower or any Restricted Subsidiary prior to the date of this Agreement and identified on Schedule 6.12(a); provided, that this subsection (a) shall not be deemed to permit an amendment to the facilities referred to in this subsection (a) which has the effect of increasing the available commitments thereunder; or

(b) Lease Obligations (1) under leases for any office buildings in which the Borrower or any of its Subsidiaries has or will have offices; (2) under leases for any equipment not to exceed $10,000,000 in the aggregate outstanding at any time; or (3) described in clause (i) of the definition thereof of the Borrower and its Restricted Subsidiaries if, immediately after the incurrence of any such Lease Obligation, the outstanding aggregate principal amount of all such Lease Obligations (other than those Lease Obligations incurred under subsections (c), (j), (l) and (q) below) would not exceed 2% of Consolidated Tangible Net Assets; or

(c) Indebtedness of (i) any Asset Company under any Project Financing Facility or (ii) any Investment Vehicle under any Project Financing Facility; provided, that if any Asset Company owned (directly or indirectly) by such Investment Vehicle has incurred any Indebtedness under a Project Financing Facility, then such Investment Vehicle may only incur Indebtedness under a Project Financing Facility if (I)(x) after giving effect to such Indebtedness, the Ratio of Cash Flow to Fixed Charges of the Borrower would not be less than 2.0:1.0, calculated on a pro forma basis to include such Indebtedness and related cash flows, (y) the Borrower's senior unsecured long-term debt is, at the time of such incurrence, rated at least BBB by S&P and Baa2 by Moody's (or if ratings of such debt have not been issued by such rating agencies, such debt is impliedly rated by an issuer rating or indicative rating of at least BBB by S&P and Baa2 by Moody's), and (z) the Borrower obtains a reaffirmation of such ratings from S&P and Moody's (taking into account the Indebtedness to be incurred by such Investment Vehicle under this Section 6.12 (c)) or (II) such Investment Vehicle owns only one Asset Company and such Indebtedness is incurred in connection with a Project Financing Facility and the proceeds thereof are promptly invested in such Asset Company; or

(d) Trading Arrangements and Credit Support Arrangements, to the extent such arrangements constitute Indebtedness; or

(e) Indebtedness with respect to any securitization, receivables financing or similar transaction entered into by ET Holdings, GTN, USGenNE or any of their respective Subsidiaries; or

(f) Indebtedness not otherwise permitted under this Section 6.12, existing on the date of this Agreement and set forth on Schedule 6.12(f) or Schedule 6.13; or

(g) Indebtedness under any Swap; or

(h) Permitted Subordinated Indebtedness; or

(i) Indebtedness between any of the Borrower, any Restricted Subsidiary, Investment Vehicle, any Asset Company or any Indebtedness under any short-term overdraft lines of credit or similar arrangements entered into in the ordinary course of business, in each case associated with the Borrower's cash management program; or

(j) Indebtedness attributable to any Permitted Sale-Leaseback Transactions; or

(k) Any Guaranty constituting Indebtedness of the Borrower or any Restricted Subsidiary, Investment Vehicle or Asset Company under clause (ix) of the definition of "Indebtedness" to the extent that the obligations covered by such Guaranty are not reasonably quantifiable under GAAP; or

(l) other Indebtedness of the Borrower or any Restricted Subsidiary (other than PG&E Gen) incurred after the date of this Agreement, provided that (i) after giving effect to any such Indebtedness, the Ratio of Cash Flow to Fixed Charges of the Borrower would not be less than 2.0:1.0 (calculated on a pro forma basis as of the end of the most recent fiscal quarter with respect to which financial statements of the Borrower are available and assuming for such purpose that such Indebtedness was incurred one year prior to the end of such fiscal quarter and taking into account any related cash flows) and (ii) if such Indebtedness would constitute Indebtedness of a Restricted Subsidiary, no Asset Company, Investment Vehicle or Restricted Subsidiary owned directly or indirectly by such Restricted Subsidiary has Indebtedness outstanding which would otherwise be permitted under Section 6.12(a), (b)(3), (c), (h), (j), (l),
(o) or (p); provided, further, that clause (ii) of this Section 6.12(l) will not be applicable if the Borrower obtains a reaffirmation of the rating of its senior unsecured long-term debt of at least BBB by S&P and Baa2 by Moody's (or if ratings of such debt have not been issued by such rating agencies, such debt is impliedly rated by an issuer rating or indicative rating of at least BBB by S&P and Baa2 by Moody's) after taking into account the Indebtedness to be incurred by such Restricted Subsidiary and related cash flows; or

(m) Indebtedness of the Borrower or any Restricted Subsidiary in respect of letters of credit or surety, performance or bid bonds used in the ordinary course of business not in excess of $25,000,000 in the aggregate outstanding at any time; or

(n) Indebtedness constituting intercompany loans (1) between the Borrower and its Restricted Subsidiaries or between such Restricted Subsidiaries or (2) made by the Borrower, any Restricted Subsidiary, any Investment Vehicle or any Asset Company to any Investment Vehicle or any Asset Company or (3) made by any Investment Vehicle to the Borrower, any Restricted Subsidiary, or any other Investment Vehicle; or

(o) Equity Funding Arrangements; or

(p) without limiting the ability to incur Indebtedness under the other subsections of this Section 6.12, any refinancing of any Indebtedness permitted under Section 6.12(f) and under the Refinanceable Facilities, provided that either (i) (x) the average life of any refinanced Indebtedness shall not be less than the average life of the Indebtedness so refinanced (plus fees and expenses, including any premium or defeasance costs, of such refinancing), taking into

account the prepayment or repayment of a portion of any such Indebtedness, and
(y) the principal amount of the refinanced Indebtedness shall not exceed the principal amount plus accrued interest thereon of the Indebtedness so refinanced, or (ii) the Borrower shall demonstrate pro forma compliance with the financial ratio described in Section 6.12(l) above; or

(q) Indebtedness of any Subsidiary of the Borrower existing at the time such Person becomes a Subsidiary of the Borrower (except for any such Indebtedness of such Subsidiary incurred in contemplation of or to finance the acquisition of such Subsidiary).

SECTION 6.13 Transactions with Affiliates. The Borrower will not enter into, or permit any Restricted Subsidiary, Investment Vehicle or Asset Company to enter into, any transaction with any Affiliate of the Borrower (other than the Borrower, any Subsidiary of the Borrower, any Investment Vehicle and any Asset Company), except:

(a) transactions with such Affiliates upon fair and reasonable terms which are no less favorable to the Borrower than would be obtained in a comparable arm's length transaction with a Person not an Affiliate of the Borrower;

(b) management, operating, sharing or other similar services arrangements or promissory notes between and among the Borrower, its Subsidiaries and its other Affiliates either existing on the date hereof and described on Schedule 6.13 or, other than in the case of promissory notes, entered into after the date hereof on commercially reasonable terms;

(c) tax sharing arrangements between the Borrower and PG&E Corp. approximating the tax position that the Borrower would be in if it were not part of PG&E Corp.'s consolidated group, as determined by the management of the Borrower in its reasonable business judgment or such other arrangements as may be approved by the Lenders prior to the date hereof; or

(d) paying or declaring any Distribution to the extent permitted under
Section 6.14.

The provisions of this Section 6.13 shall not apply to (i) transactions between the Borrower or any of its Subsidiaries, on the one hand, and any employee of the Borrower or any of its Subsidiaries, on the other hand, that are approved by the Board of Directors of the Borrower or any committee of the Board of Directors and (ii) the payment of reasonable and customary regular fees to directors of the Borrower or any Subsidiary of the Borrower.

SECTION 6.14 Distributions. The Borrower will not declare or make any Distribution if (a) a Default, Event of Default or Downgrade Event has occurred and is continuing or shall occur after giving effect to such Distribution, (b) the Ratio of Cash Flow to Fixed Charges of the Borrower determined as of the end of the immediately preceding fiscal quarter was not at least 2.0:1.0 or (c) the Borrower fails to satisfy the requirements of the test set forth in Section 6.15(b), or the Borrower fails to have a Consolidated Net Worth of at least $2.15 billion, in each case calculated on a pro forma basis as of the end of the most recent fiscal period with respect to which financial statements of the Borrower are available (assuming such Distribution and all material events with respect to the Borrower and its Subsidiaries which occurred after the end of such fiscal period had occurred on the last day of such fiscal period); provided that the Borrower may declare and make Distributions of assets of or equity ownership interests in any Unrestricted Subsidiary at any time without complying with the foregoing.

SECTION 6.15 Financial Covenants.

(a) The Borrower shall not, as of the end of each fiscal quarter, permit the Ratio of Cash Flow to Fixed Charges to be less than 1.5:1.0.

(b) The Borrower shall not, as of the end of each fiscal quarter, permit the Ratio of Debt to Capitalization to be greater than 0.6:1.0.

(c) The Borrower shall not, at the end of each fiscal quarter, permit (i) Consolidated Net Worth to be less than the Minimum Consolidated Net Worth and
(ii) Non-Trading Consolidated Net Worth to be less than the Minimum Non-Trading Consolidated Net Worth.

SECTION 6.16 Separateness from PG&E Corp. The Borrower shall (i) maintain adequate capital in light of the business in which it is engaged; (ii) maintain books and corporate records separate from PG&E Corp. and PG&E; (iii) not commingle assets with PG&E Corp. or PG&E; and (iv) conduct business in its own name and hold itself out as separate from PG&E Corp. and PG&E. The Borrower shall promptly notify the Administrative Agent upon a Responsible Officer of the Borrower obtaining Actual Knowledge that a creditor of PG&E Corp. or of PG&E has made a claim or filing in writing seeking the substantive consolidation of NEG LLC in any bankruptcy proceeding of PG&E Corp. or of PG&E.

SECTION 6.17 Asset Sales. Except for the sale of all or substantially all of the assets of the Borrower pursuant to Section 6.9, and other than assets required to be sold to conform with governmental regulations, the Borrower shall not, and shall cause its Subsidiaries not to, sell or otherwise dispose of any assets (other than short-term, readily marketable investments purchased for cash management purposes with funds not representing the proceeds of other asset sales) if, on a pro forma basis, the aggregate net book value of all such sales during the most recent 12-month period would exceed 10% of Consolidated Tangible Net Assets computed as of the end of the most recent quarter preceding such sale; provided, however, that any such sales shall be disregarded for purposes of this 10% limitation if the proceeds are invested in assets in the Borrower's business in the energy trading, energy services, power generation, electric transmission or gas transmission and storage businesses or in similar or related lines of business, and, provided further, that the Borrower may sell or otherwise dispose of assets in excess of such 10% limitation if the proceeds from such sales or dispositions, which are not reinvested as provided above, are retained by the Borrower as cash or Cash Equivalents or are used by the Borrower to prepay the Loans hereunder or to purchase and retire notes or Indebtedness ranking pari passu in right of payment to the Loans or Indebtedness of the Borrower's Subsidiaries. (For the avoidance of doubt, any sale of assets otherwise permitted by this Section 6.17 shall not be permitted if such sale would result in a violation of any other provision of this Agreement.)

ARTICLE VII

EVENTS OF DEFAULT

SECTION 7.1 Events of Default. If any of the following events shall occur and be continuing:

(a) The Borrower shall fail to pay any principal of any Loan when due in accordance with the terms hereof; or the Borrower shall fail to pay any interest on any Loan, or any other amount payable hereunder or under any other Loan Document, within five days after any such interest or other amount becomes due in accordance with the terms hereof or thereof; or

(b) Any representation or warranty made or deemed made by the Borrower herein or in any other Loan Document or that is contained in any certificate, document or financial or other statement furnished by it at any time under or in connection with this Agreement or any such other Loan Document shall prove to have been inaccurate in any material respect on or as of the date made or deemed made or furnished; or

(c) the Borrower shall default in any material respect in the due observance or performance of any agreement contained in Sections 6.1, 6.2, 6.9, 6.11, 6.12, 6.13, 6.14, 6.15 or 6.16; or

(d) the Borrower shall default in the observance or performance of any other agreement contained in this Agreement or any other Loan Document (other than as provided in paragraphs (a) through (c) of this Section), and such default shall continue unremedied for a period of 30 days after notice thereof from the Administrative Agent, which may be at the request of any Lender, to the Borrower; or

(e) the Borrower or any Restricted Subsidiary shall default in respect of any Indebtedness or default in its obligations to make payments when due under any Equity Funding Arrangements which at the time have an aggregate principal amount outstanding or, in the case of Equity Funding Arrangements, due and unpaid, in excess of $50,000,000, and such Indebtedness is then due and payable in full at maturity or as a result thereof such Indebtedness shall have been accelerated or otherwise become due or subject to prepayment in full prior to its stated maturity; or

(f) an involuntary proceeding shall be commenced or an involuntary petition shall be filed in a court of competent jurisdiction seeking (i) relief in respect of the Borrower or any Restricted Subsidiary or of a substantial part of the property or assets of the Borrower or any Restricted Subsidiary under Title 11 of the United States Code, as now constituted or hereafter amended, or any other Federal or state bankruptcy, insolvency, receivership or similar law, (ii) the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for the Borrower or any Restricted Subsidiary or (other than in connection with any proceeding relating solely to one or more Unrestricted Subsidiaries, Investment Vehicles or Project Companies of the Borrower) for a substantial part of the property or assets of the Borrower or any Restricted Subsidiary or (iii) the winding up or liquidation of the Borrower or any Restricted Subsidiary; and such proceeding or petition shall continue undismissed for 60 days or an order or decree approving or ordering any of the foregoing shall be entered; or

(g) the Borrower or any Restricted Subsidiary shall (i) voluntarily commence any proceeding or file any petition seeking relief under Title 11 of the United States Code, as now constituted or hereafter amended, or any other Federal or state bankruptcy, insolvency, receivership or similar law, (ii) consent to the institution of, or fail to contest in a timely and appropriate manner, any proceeding or the filing of any petition described in Section 7.1(f)

above, (iii) apply for or consent to the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for the Borrower or any Restricted Subsidiary (other than in connection with any proceeding relating solely to one or more Unrestricted Subsidiaries, Investment Vehicles or Project Companies of the Borrower) for a substantial part of the property or assets of the Borrower or any Restricted Subsidiary, (iv) file an answer admitting the material allegations of a petition filed against it in any such proceeding, (v) make a general assignment for the benefit of creditors, or (vi) take any corporate action for the purpose of effecting any of the foregoing, become unable, admit in writing its inability, or fail generally, to pay its debts as they become due; or

(h) one or more final judgments for the payment of money in an aggregate amount in excess of $50,000,000 (exclusive of amounts covered by insurance) shall be rendered against the Borrower or any Restricted Subsidiary and such judgment or order shall remain undischarged, unbonded or unstayed for a period of 60 days; or

(i) an ERISA Event shall have occurred that, either alone or in combination with other ERISA Events that shall have occurred, is reasonably likely to result in a Material Adverse Effect; or

(j) a court of competent jurisdiction shall issue an order, decree or judgment requiring the substantive consolidation of the Borrower with PG&E Corp. or PG&E or a court of competent jurisdiction with administrative oversight over the assets and liabilities of PG&E Corp. or PG&E shall issue an order, decree or judgment otherwise subjecting the any material assets and liabilities of the Borrower to administration by such court; then, and in any such event, (A) if such event is an Event of Default specified in paragraphs (f) or (g) above with respect to the Borrower, automatically the Commitments shall immediately terminate and the Loans hereunder (with accrued interest thereon) and all other amounts owing under this Agreement and the other Loan Documents (including all L/C Obligations, whether or not the beneficiaries of the then outstanding Letters of Credit shall have presented the documents required for drawings thereunder) shall immediately become due and payable, and (B) if such event is any other Event of Default, either or both of the following actions may be taken: (i) with the consent of the Required Lenders, the Administrative Agent may, or upon the request of the Required Lenders, the Administrative Agent shall, by notice to the Borrower declare the Commitments to be terminated forthwith, whereupon the Commitments shall immediately terminate; and (ii) with the consent of the Required Lenders, the Administrative Agent may, or upon the request of the Required Lenders, the Administrative Agent shall, by notice to the Borrower, declare the Loans hereunder (with accrued interest thereon) and all other amounts owing under this Agreement and the other Loan Documents (including all L/C Obligations, whether or not the beneficiaries of the then outstanding Letters of Credit shall have presented the documents required for drawings thereunder) to be due and payable forthwith, whereupon the same shall immediately become due and payable. In the case of all Letters of Credit with respect to which presentment for honor shall not have occurred at the time of an acceleration pursuant to this paragraph, the Borrower shall at such time deposit in a cash collateral account opened by the Administrative Agent (the "Cash Collateral Account") an amount equal to the then aggregate undrawn and unexpired amount of such Letters of Credit. The Borrower shall grant a security interest on the Cash Collateral Account to the Administrative Agent, for the benefit of the

Lenders, on such terms as are reasonably satisfactory to the Administrative Agent. Amounts held in the Cash Collateral Account shall be applied by the Administrative Agent to the payment of drafts drawn under such Letters of Credit, and the unused portion thereof after all such Letters of Credit shall have expired or been fully drawn upon, if any, shall be applied to repay other obligations of the Borrower hereunder and under the other Loan Documents. After all such Letters of Credit shall have expired or been fully drawn upon, all Reimbursement Obligations shall have been satisfied and all other obligations of the Borrower hereunder and under the other Loan Documents shall have been paid in full, the balance, if any, in the Cash Collateral Account shall be returned to the Borrower (or such other Person as may be lawfully entitled thereto). Except as expressly provided above in this Section, presentment, demand, protest and all other notices of any kind are hereby expressly waived by the Borrower.

ARTICLE VIII

THE AGENTS

SECTION 8.1 Appointment. Each Lender (the term "Lender" as used in this Section 9 to include the Issuing Bank, except as specified below) hereby irrevocably designates and appoints the Administrative Agent as the Administrative Agent of such Lender under this Agreement and the other Loan Documents, and each Lender irrevocably authorizes the Administrative Agent, in such capacity, to take such action on its behalf under the provisions of this Agreement and the other Loan Documents and to exercise such powers and perform such duties as are expressly delegated to the Administrative Agent by the terms of this Agreement and the other Loan Documents, together with such other powers as are reasonably incidental thereto. Notwithstanding any provision to the contrary elsewhere in this Agreement, the Administrative Agent shall not have any duties or responsibilities, except those expressly set forth herein, or any fiduciary relationship with any Lender, and no implied covenants, functions, responsibilities, duties, obligations or liabilities shall be read into this Agreement or any other Loan Document or otherwise exist against the Administrative Agent.

SECTION 8.2 Delegation of Duties. The Administrative Agent may execute any of its duties under this Agreement and the other Loan Documents by or through agents or attorneys-in-fact and shall be entitled to advice of counsel concerning all matters pertaining to such duties. The Administrative Agent shall not be responsible for the negligence or misconduct of any agents or attorneys in fact selected by it with reasonable care.

SECTION 8.3 Exculpatory Provisions. None of the Agents or any of their respective officers, directors, employees, agents, attorneys-in-fact or affiliates shall be (i) liable for any action lawfully taken or omitted to be taken by it or such Person under or in connection with this Agreement or any other Loan Document (except to the extent that any of the foregoing are found by a final and non-appealable decision of a court of competent jurisdiction to have resulted from its or such Person's own gross negligence or willful misconduct) or (ii) responsible in any manner to any of the Lenders for any recitals, statements, representations or warranties made by the Borrower or any officer thereof contained in this Agreement or any other Loan Document or in any certificate, report, statement or other document referred to or provided for in, or received by the Agents under or in connection with, this Agreement or any other Loan Document or for the value, validity, effectiveness, genuineness, enforceability or sufficiency of this Agreement or any other Loan Document or for any failure of the Borrower to perform its obligations hereunder or thereunder. The Agents shall not be under any obligation to any Lender to ascertain or to inquire as to the observance or performance of any of the agreements contained in, or conditions of, this Agreement or any other Loan Document, or to inspect the properties, books or records of the Borrower.

SECTION 8.4 Reliance by Administrative Agent. The Administrative Agent shall be entitled to rely, and shall be fully protected in relying, upon any instrument, writing, resolution, notice, consent, certificate, affidavit, letter, telecopy, telex or teletype message, statement, order or other document or conversation believed by it to be genuine and correct and

to have been signed, sent or made by the proper Person or Persons and upon advice and statements of legal counsel (including, without limitation, counsel to the Borrower), independent accountants and other experts selected by the Administrative Agent. The Administrative Agent may deem and treat the payee of any Note as the owner thereof for all purposes unless such Note shall have been transferred in accordance with Section 9.6 and all actions required by such
Section in connection with such transfer shall have been taken. The Administrative Agent shall be fully justified in failing or refusing to take any action under this Agreement or any other Loan Document unless it shall first receive such advice or concurrence of the Required Lenders (or, if so specified by this Agreement, all Lenders or any other instructing group of Lenders specified by this Agreement) as it deems appropriate or it shall first be indemnified to its satisfaction by the Lenders against any and all liability and expense that may be incurred by it by reason of taking or continuing to take any such action. The Administrative Agent shall in all cases be fully protected in acting, or in refraining from acting, under this Agreement and the other Loan Documents in accordance with a request of the Required Lenders (or, if so specified by this Agreement, all Lenders or any other instructing group of Lenders specified by this Agreement), and such request and any action taken or failure to act pursuant thereto shall be binding upon all the Lenders and all future holders of the Loans.

SECTION 8.5 Notice of Default. The Administrative Agent shall not be deemed to have knowledge or notice of the occurrence of any Default or Event of Default hereunder unless the Administrative Agent shall have received notice from a Lender, or the Borrower referring to this Agreement, describing such Default or Event of Default and stating that such notice is a "notice of default". In the event that the Administrative Agent shall receive such a notice, the Administrative Agent shall give notice thereof to the Lenders. The Administrative Agent shall take such action with respect to such Default or Event of Default as shall be reasonably directed by the Required Lenders (or, if so specified by this Agreement, all Lenders or any other instructing group of Lenders specified by this Agreement); provided that unless and until the Administrative Agent shall have received such directions, the Administrative Agent may (but shall not be obligated to) take such action, or refrain from taking such action, with respect to such Default or Event of Default as it shall deem advisable in the best interests of the Lenders.

SECTION 8.6 Non-Reliance on Administrative Agent and Other Lenders. Each Lender expressly acknowledges that none of the Agents or any of their respective officers, directors, employees, agents, attorneys-in-fact or affiliates have made any representations or warranties to it and that no act by any Agent hereafter taken, including any review of the affairs of the Borrower or any affiliate of the Borrower, shall be deemed to constitute any representation or warranty by any Agent to any Lender. Each Lender represents to the Agents that it has, independently and without reliance upon any Agent or any other Lender, and based on such documents and information as it has deemed appropriate, made its own appraisal of and investigation into the business, operations, property, financial and other condition and creditworthiness of the Borrower and their affiliates and made its own decision to make its Loans hereunder and enter into this Agreement. Each Lender also represents that it will, independently and without reliance upon any Agent or any other Lender, and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit analysis, appraisals and decisions in taking or not taking action under this Agreement and the other Loan Documents, and to make such investigation as it deems necessary to inform itself as to the

business, operations, property, financial and other condition and creditworthiness of the Borrower and their affiliates. Except for notices, reports and other documents expressly required to be furnished to the Lenders by the Administrative Agent hereunder, the Administrative Agent shall not have any duty or responsibility to provide any Lender with any credit or other information concerning the business, operations, property, condition (financial or otherwise), prospects or creditworthiness of the Borrower or any affiliate of the Borrower that may come into the possession of the Administrative Agent or any of its officers, directors, employees, agents, attorneys-in-fact or affiliates.

SECTION 8.7 Indemnification. The Lenders (other than the Issuing Bank) agree to indemnify each Agent in its capacity as such (to the extent not reimbursed by the Borrower and without limiting the obligation of the Borrower to do so), ratably according to their respective Aggregate Exposure Percentages in effect on the date on which indemnification is sought under this Section (or, if indemnification is sought after the date upon which the Commitments shall have terminated and the Loans shall have been paid in full, ratably in accordance with such Aggregate Exposure Percentages immediately prior to such date), for, and to save each Agent harmless from and against, any and all liabilities, obligations, losses, damages, penalties, actions, judgments, suits, costs, expenses or disbursements of any kind whatsoever that may at any time

(including, without limitation, at any time following the payment of the Loans)
be imposed on, incurred by or asserted against such Agent in any way relating to or arising out of, the Commitments, this Agreement, any of the other Loan Documents or any documents contemplated by or referred to herein or therein or the transactions contemplated hereby or thereby or any action taken or omitted by such Agent under or in connection with any of the foregoing; provided that no Lender shall be liable for the payment of any portion of such liabilities, obligations, losses, damages, penalties, actions, judgments, suits, costs, expenses or disbursements that are found by a final and non-appealable decision of a court of competent jurisdiction to have resulted from such Agent's gross negligence or willful misconduct. The agreements in this Section 8.7 shall survive the payment of the Loans and all other amounts payable hereunder.

SECTION 8.8 Agent in Its Individual Capacity. Each Agent, in its individual capacity, and its affiliates may make loans to, accept deposits from and generally engage in any kind of business with the Borrower as though such Agent were not the Agent. With respect to its Loans made or renewed by it and with respect to any Letter of Credit issued or participated in by it, each Agent, in its individual capacity, shall have the same rights and powers under this Agreement and the other Loan Documents as any Lender and may exercise the same as though it were not an Agent, and the terms "Lender" and "Lenders" shall include the Agent, in its individual capacity.

SECTION 8.9 Successor Administrative Agent. The Administrative Agent may resign as Administrative Agent upon (i) 10 Business Day's notice to the Lenders and the Borrower and (ii) the appointment of a successor Administrative Agent in accordance with this Section 8.9. If the Administrative Agent shall give notice of its intent to resign as Administrative Agent under this Agreement and the other Loan Documents, then the Required Lenders shall appoint from among the Lenders a successor Administrative Agent for the Lenders, which successor Administrative Agent shall (unless an Event of Default under Section 7.1(a) or
Section 7.1(f) or Section 7.1(g) with respect to the Borrower shall have occurred and be continuing) be

subject to approval by the Borrower (which approval shall not be unreasonably withheld or delayed), whereupon such successor Administrative Agent shall succeed to the rights, powers and duties of the Administrative Agent, and the term "Administrative Agent" shall mean such successor Administrative Agent effective upon such appointment and approval, and the former Administrative Agent's rights, powers and duties as Administrative Agent shall be terminated, without any other or further act or deed on the part of such former Administrative Agent or any of the parties to this Agreement or any holders of the Loans. If no successor agent has accepted appointment as Administrative Agent by the date that is 30 days following a retiring Administrative Agent's notice of resignation, the retiring Administrative Agent's resignation shall nevertheless thereupon become effective, and the Lenders shall assume and perform all of the duties of the Administrative Agent hereunder until such time, if any, as the Required Lenders appoint a successor agent as provided for above. After any retiring Administrative Agent's resignation as Administrative Agent, the provisions of this Section 8 shall inure to its benefit as to any actions taken or omitted to be taken by it while it was Administrative Agent under this Agreement and the other Loan Documents.

SECTION 8.10 Documentation and Syndication Agents. Neither the Documentation Agents nor the Syndication Agents shall have any duties or responsibilities hereunder in their capacities as such.

ARTICLE IX

MISCELLANEOUS

SECTION 9.1 Amendments and Waivers. Neither this Agreement or any other Loan Document, nor any terms hereof or thereof may be amended, supplemented or modified except in accordance with the provisions of this Section 9.1. The Required Lenders and the Borrower may, or (with the written consent of the Required Lenders) the Administrative Agent and the Borrower may, from time to time, (a) enter into written amendments, supplements or modifications hereto and to the other Loan Documents (including amendments and restatements hereof or thereof) for the purpose of adding any provisions to this Agreement or the other Loan Documents or changing in any manner the rights of the Lenders or of the Borrower hereunder or thereunder or (b) waive, on such terms and conditions as may be specified in the instrument of waiver, any of the requirements of this Agreement or the other Loan Documents or any Default or Event of Default and its consequences; provided, however, that no such waiver and no such amendment, supplement or modification shall:

(i) forgive any part of the principal amount or extend the final scheduled date of maturity of any Loan or Reimbursement Obligation or extend the expiry date of any Letter of Credit (beyond the dates provided in Section 2.1(a) and 2.1(b)), reduce the stated rate of any interest or fee payable hereunder or extend the scheduled date of any payment thereof, or increase the amount or extend the expiration date of any Commitment of any Lender, in each case without the written consent of each Lender or Issuing Bank, as the case may be, directly affected thereby;

(ii) amend, modify or waive any provision of this Section or reduce any percentage specified in the definition of Required Lenders, or consent to the assignment or transfer by the

Borrower of any of its rights and obligations under this Agreement and the other Loan Documents;

(iii) eliminate or reduce the voting rights of any Lender under this Section 9.1 without the written consent of such Lender;

(iv) amend, modify or waive any provision of Section 3.12 or the definition of Aggregate Exposure Percentages without the written consent of each Lender directly affected thereby; or

(v) amend, modify or waive any provision of Section 2 without the written consent of the Issuing Bank.

Any such waiver and any such amendment, supplement or modification shall apply equally to each of the Issuing Bank and the Lenders and shall be binding upon the Borrower, the Issuing Bank, the Lenders and the Administrative Agent. In the case of any waiver, the Borrower, the Issuing Bank, the Lenders and the Administrative Agent shall be restored to their former position and rights hereunder and under the other Loan Documents, and any Default or Event of Default waived shall be deemed to be cured and not continuing; but no such waiver shall extend to any subsequent or other Default or Event of Default, or impair any right consequent thereon. Any such waiver, amendment, supplement or modification shall be effected by a written instrument signed by the parties required to sign pursuant to the foregoing provisions of this Section; provided, that delivery of an executed signature page of any such instrument by facsimile transmission shall be effective as delivery of a manually executed counterpart thereof.

SECTION 9.2 Notices. All notices, requests and demands to or upon the respective parties hereto to be effective shall be in writing (including by telecopy), and, unless otherwise expressly provided herein, shall be deemed to have been duly given or made when delivered, or three Business Days after being deposited in the mail, postage prepaid, or, in the case of telecopy notice, when received, addressed (a) in the case of the Borrower, the Issuing Bank and the Administrative Agent, as follows and (b) in the case of the Lenders, as set forth on Schedule 1.1B hereto, or, in the case of a Lender which becomes a party to this Agreement pursuant to an Assignment and Acceptance, in such Assignment and Acceptance or (c) in the case of any party, to such other address as such party may hereafter notify to the other parties hereto:

The Borrower:

PG&E National Energy Group, Inc.
7500 Old Georgetown Road
Bethesda, Maryland 20814

Attention: Senior Vice President and General Counsel Facsimile: (301) 280-6319
Telephone: (301) 280-6815

The Administrative Agent:

The Chase Manhattan Bank
One Chase Manhattan Plaza
8th Floor
New York, New York 10081
Attention: Jacqueline D. Reid Facsimile: (212) 552-7683
Telephone: (212) 552-5777

The Issuing Bank:

The Chase Manhattan Bank
4 Chase MetroTech Center, 8/th/ Floor
Brooklyn, New York 11245-0001

Attention: Standby Letter of Credit Department Facsimile: (718) 242-6501
Telephone: (718) 242-5045

provided, that any notice, request or demand to or upon the Administrative Agent, the Issuing Bank or any Lender shall not be effective until received. All Applications for Issuance shall be delivered to the Issuing Bank as follows:

Deliver Application for Issuance to:

The Chase Manhattan Bank
4 Chase MetroTech Center, 8/th/ Floor
Brooklyn, New York 11245-0001

Attention: Standby Letter of Credit Department Facsimile: (718) 242-6501
Telephone: (718) 242-5045

SECTION 9.3 No Waiver; Cumulative Remedies. No failure to exercise and no delay in exercising, on the part of the Administrative Agent, the Issuing Bank or any Lender, any right, remedy, power or privilege hereunder or under the other Loan Documents shall operate as a waiver thereof; nor shall any single or partial exercise of any right, remedy, power or privilege hereunder preclude any other or further exercise thereof or the exercise of any other right, remedy, power or privilege. The rights, remedies, powers and privileges herein provided are cumulative and not exclusive of any rights, remedies, powers and privileges provided by law.

SECTION 9.4 Survival of Representations and Warranties. All representations and warranties made herein, in the other Loan Documents and in any document, certificate or statement delivered pursuant hereto or in connection herewith shall survive the execution and delivery of this Agreement and the making of the Loans and other extensions of credit hereunder.

SECTION 9.5 Payment of Expenses. The Borrower agrees (a) to pay or reimburse the Issuing Bank and the Administrative Agent for all their reasonable out-of-pocket costs and expenses incurred in connection with the syndication of the facilities herein (other than fees payable to syndicate members) and the development, preparation and execution of, and any amendment, supplement or modification to, this Agreement and the other Loan Documents and

any other documents prepared in connection herewith or therewith, and the consummation and administration of the transactions contemplated hereby and thereby, including, without limitation, the reasonable fees and disbursements and other charges of single counsel to both the Issuing Bank and the Administrative Agent, (b) to pay or reimburse the Issuing Bank, each Lender and the Administrative Agent for all their costs and expenses incurred in connection with the enforcement or preservation of any rights under this Agreement, the other Loan Documents and any other documents prepared in connection herewith or therewith, including, without limitation, the fees and disbursements of counsel to the Lenders, the Issuing Bank and the Administrative Agent, (c) to pay, indemnify, or reimburse the Issuing Bank, each Lender and the Administrative Agent for, and hold the Issuing Bank, each Lender and the Administrative Agent harmless from, any and all recording and filing fees and any and all liabilities with respect to, or resulting from any delay in paying, stamp, excise and other taxes, if any, which may be payable or determined to be payable in connection with the execution and delivery of, or consummation or administration of any of the transactions contemplated by, or any amendment, supplement or modification of, or any waiver or consent under or in respect of, this Agreement, the other Loan Documents and any such other documents, and (d) to pay, indemnify or reimburse the Issuing Bank, each Lender, the Administrative Agent, their respective affiliates, and their respective officers, directors, trustees, employees, advisors, Administrative Agents and controlling persons (each, an "Indemnitee") for, and hold each Indemnitee harmless from and against any and all other liabilities, obligations, losses, damages, penalties, actions, judgments, suits, costs, expenses or disbursements of any kind or nature whatsoever with respect to the execution, delivery, enforcement, performance and administration of, and the syndication of commitments under, this Agreement, the other Loan Documents and any such other documents or any investigation, litigation or proceeding relating to or arising out of any of the foregoing (whether or not any Indemnitee is a party thereto), including, without limitation, any of the foregoing relating to the use of proceeds of the Loans and the fees and disbursements and other charges of legal counsel in connection with claims, actions or proceedings by any Indemnitee against the Borrower hereunder (all the foregoing in this clause (d), collectively, the "Indemnified Liabilities"), provided, that the Borrower shall have no obligation hereunder to any Indemnitee with respect to Indemnified Liabilities to the extent such Indemnified Liabilities are found by a final and non-appealable decision of a court of competent jurisdiction to have resulted from the gross negligence or willful misconduct of such Indemnitee. All amounts due under this Section shall be payable not later than 30 days after written demand therefor. Statements payable by the Borrower pursuant to this Section shall be submitted to PG&E National Energy Group, Inc. Attention: Accounts Payable (Telephone No. 301-280-6800) (Fax No. 301-280-6900), at the address of the Borrower set forth in Section 9.2, or to such other Person or address as may be hereafter designated by the Borrower in a notice to the Administrative Agent. The agreements in this Section shall survive repayment of the Loans and all other amounts payable hereunder.

Section 9.6 Successors and Assigns; Participations and Assignments.

(a) This Agreement shall be binding upon and inure to the benefit of the Borrower, the Issuing Bank, the Lenders, the Administrative Agent, all future holders of the Loans and their respective successors and assigns, except that the Borrower may not assign or transfer any of its rights or obligations under this Agreement without the prior written consent of the Administrative Agent, the Issuing Bank and each Lender.

(b) Any Lender other than any Conduit Lender may, without the consent of the Borrower, in accordance with applicable law, at any time sell to one or more banks, financial institutions or other entities (each, a "Participant") participating interests in any Loan owing to such Lender, any Commitment of such Lender or any other interest of such Lender hereunder and under the other Loan Documents. In the event of any such sale by a Lender of a participating interest to a Participant, such Lender's obligations under this Agreement to the other parties to this Agreement shall remain unchanged, such Lender shall remain solely responsible for the performance thereof, such Lender shall remain the holder of any such Loan for all purposes under this Agreement and the other Loan Documents, and the Borrower, the Issuing Bank and the Administrative Agent shall continue to deal solely and directly with such Lender in connection with such Lender's rights and obligations under this Agreement and the other Loan Documents. In no event shall any Participant under any such participation have any right to approve any amendment or waiver of any provision of any Loan Document, or any consent to any departure by the Borrower therefrom, except to the extent that such amendment, waiver or consent would require the consent of all Lenders pursuant to Section 9.1. The Borrower agrees that if amounts outstanding under this Agreement and the Loans are due or unpaid, or shall have been declared or shall have become due and payable upon the occurrence of an Event of Default, each Participant shall, to the maximum extent permitted by applicable law, be deemed to have the right of setoff in respect of its participating interest in amounts owing under this Agreement to the same extent as if the amount of its participating interest were owing directly to it as a Lender under this Agreement, provided that, in purchasing such participating interest, such Participant shall be deemed to have agreed to share with the Lenders the proceeds thereof as provided in Section 9.7(a) as fully as if such Participant were a Lender hereunder. The Borrower also agrees that each Participant shall be entitled to the benefits of Sections 3.13, 3.14 and 3.15 with respect to its participation in the Commitments and the Loans outstanding from time to time as if such Participant were a Lender; provided that, in the case of Section 3.14, such Participant shall have complied with the requirements of said Section, and provided, further, that no Participant shall be entitled to receive any greater amount pursuant to any such Section than the transferor Lender would have been entitled to receive in respect of the amount of the participation transferred by such transferor Lender to such Participant had no such transfer occurred.

(c) Any Lender other than any Conduit Lender (an "Assignor") may, in accordance with applicable law and upon written notice to the Administrative Agent, at any time and from time to time assign to any Lender or any Lender Affiliate or, with the consent of the Borrower, the Issuing Bank and the Administrative Agent (which, in each case, shall not be unreasonably withheld or delayed), to an additional bank, financial institution or other entity (an "Assignee") all or any part of its rights and obligations under this Agreement pursuant to an Assignment and Acceptance, substantially in the form of Exhibit B, executed by such Assignee and such Assignor (and, where the consent of the Borrower, the Issuing Bank or the Administrative Agent is required pursuant to the foregoing provisions, by the Borrower and such other Persons) and delivered to the Administrative Agent for its acceptance and recording in the Register; provided that no such assignment to an Assignee (other than any Lender or any affiliate thereof) shall be in an aggregate principal amount of less than $10,000,000 or result in the assigning Lender holding an aggregate principal amount of less than $10,000,000 (other than in the case of an assignment of all of a Lender's interests under this Agreement), unless otherwise agreed by the Borrower and the Administrative Agent. For purposes of the proviso contained in the preceding

sentence, the amount described therein shall be aggregated in respect of each Lender and its Lender Affiliates, if any. Upon such execution, delivery, acceptance and recording, from and after the effective date determined pursuant to such Assignment and Acceptance, (x) the Assignee thereunder shall be a party hereto and, to the extent provided in such Assignment and Acceptance, have the rights and obligations of a Lender hereunder with Commitments and/or Loans as set forth therein, and (y) the Assignor thereunder shall, to the extent provided in such Assignment and Acceptance, be released from its obligations under this Agreement (and, in the case of an Assignment and Acceptance covering all of an Assignor's rights and obligations under this Agreement, such Assignor shall cease to be a party hereto, except as to Section 3.13, 3.14 and 9.5 in respect of the period prior to such effective date). Notwithstanding any provision of this Section, the consent of the Borrower shall not be required for any assignment that occurs at any time when any Event of Default shall have occurred and be continuing. Notwithstanding the foregoing, any Conduit Lender may assign at any time to its designating Lender hereunder without the consent of the Borrower or the Administrative Agent any or all of the Loans it may have funded hereunder and pursuant to its designation agreement and without regard to the limitations set forth in the first sentence of this Section 9.6(c).

(d) The Administrative Agent shall, on behalf of the Borrower, maintain at its address referred to in Section 9.2 a copy of each Assignment and Acceptance delivered to it and a register (the "Register") for the recordation of the names and addresses of the Lenders and the Commitment of, and principal amount of the Loans owing to, each Lender from time to time. The entries in the Register shall be conclusive, in the absence of manifest error, and the Borrower, the Issuing Bank, the Administrative Agent and the Lenders shall treat each Person whose name is recorded in the Register as the owner of the Loans and any Notes evidencing such Loans recorded therein for all purposes of this Agreement. Any assignment of any Loan, whether or not evidenced by a Note, shall be effective only upon appropriate entries with respect thereto being made in the Register (and each Note shall expressly so provide). Any assignment or transfer of all or part of a Loan evidenced by a Note shall be registered on the Register only upon surrender for registration of assignment or transfer of the Note evidencing such Loan, accompanied by a duly executed Assignment and Acceptance; thereupon one or more new Notes in the same aggregate principal amount shall be issued to the designated Assignee, and the old Notes shall be returned by the Administrative Agent to the Borrower marked "canceled". The Register shall be available for inspection by the Borrower or any Lender (with respect to any entry relating to such Lender's Loans) at any reasonable time and from time to time upon reasonable prior notice.

(e) Upon its receipt of an Assignment and Acceptance executed by an Assignor, an Assignee and any other Person whose consent is required by Section 9.6(c), together with payment by either the Assignor or the Assignee, as they may agree upon between themselves, to the Administrative Agent of a registration and processing fee of $4,000 (provided, that such registration and processing fee shall not be required to be paid if the assignment is between a Lender and such Lender's Lender Affiliate), the Administrative Agent shall (i) promptly accept such Assignment and Acceptance and (ii) on the effective date determined pursuant thereto record the information contained therein in the Register and give notice of such acceptance and recordation to the Borrower. On or prior to such effective date, the Borrower, at its own expense, upon request, shall execute and deliver to the Administrative Agent (in exchange for the Note of the assigning Lender) new Note to the order of such Assignee in an amount equal to the

applicable Loans assumed or acquired by it pursuant to such Assignment and Acceptance and, if the Assignor has retained Commitments, upon request, a new Note to the order of the Assignor in an amount equal to the applicable Loans retained by it hereunder. Such new Note or Notes shall be dated the Closing Date and shall otherwise be in the form of the Note or Notes replaced thereby.

(f) For avoidance of doubt, the parties to this Agreement acknowledge that the provisions of this Section concerning assignments of Loans and Notes relate only to absolute assignments and that such provisions do not prohibit assignments creating security interests in Loans and Notes, including, without limitation, any pledge or assignment by a Lender of any Loan or Note to any Federal Reserve Bank in accordance with applicable law.

(g) Each of the Borrower, each Lender and the Administrative Agent hereby confirms that it will not institute against a Conduit Lender or join any other Person in instituting against a Conduit Lender any bankruptcy, reorganization, arrangement, insolvency or liquidation proceeding under any state bankruptcy or similar law, for one year and one day after the payment in full of the latest maturing commercial paper note issued by such Conduit Lender; provided, however, that each Lender designating any Conduit Lender hereby agrees to indemnify, save and hold harmless each other party hereto for any loss, cost, damage or expense arising out of its inability to institute such a proceeding against such Conduit Lender during such period of forbearance.

SECTION 9.7 Adjustments; Set-off.

(a) Except to the extent that this Agreement provides for payments to be allocated to a particular Lender or to the Lenders, if any Lender (a "Benefited Lender") shall at any time receive any payment of all or part of the Obligations owing to it, or receive any collateral in respect thereof (whether voluntarily or involuntarily, by set-off, pursuant to events or proceedings of the nature referred to in Section 7.1(f), Section 7.1(g) or otherwise), in a greater proportion than any such payment to or collateral received by any other Lender, if any, in respect of the Obligations owing to Lender, such Benefited Lender shall purchase for cash from the other Lenders a participating interest in such portion of the Obligations owing to each such other Lender, or shall provide such other Lenders with the benefits of any such collateral, as shall be necessary to cause such Benefited Lender to share the excess payment or benefits of such collateral ratably with each of the Lenders; provided, however, that if all or any portion of such excess payment or benefits is thereafter recovered from such Benefited Lender, such purchase shall be rescinded, and the purchase price and benefits returned, to the extent of such recovery, but without interest unless the Benefited Lender is required by law to pay interest thereon, in which case, each Lender returning funds to the Benefited Lender shall pay its pro rata share of such interest.

(b) In addition to any rights and remedies of the Lenders provided by law, each Lender shall have the right, without prior notice to the Borrower, any such notice being expressly

waived by the Borrower to the extent permitted by applicable law, upon any amount becoming due and payable by the Borrower hereunder (whether at the stated maturity, by acceleration or otherwise), to set off and appropriate and apply against such amount any and all deposits (general or special, time or demand, provisional or final), in any currency, and any other credits, indebtedness or claims, in any currency, in each case whether direct or indirect, absolute or contingent, matured or unmatured, at any time held or owing by such Lender or any branch, agency or affiliate thereof (other than any such affiliate engaged in the energy trading business) to or for the credit or the account of the Borrower. Each Lender agrees promptly to notify the Borrower and the Administrative Agent after any such setoff and application made by such Lender, provided that the failure to give such notice shall not affect the validity of such setoff and application.

SECTION 9.8 Counterparts. This Agreement may be executed by one or more of the parties to this Agreement on any number of separate counterparts, and all of said counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of an executed signature page of this Agreement or of a Lender Addendum by facsimile transmission shall be effective as delivery of a manually executed counterpart hereof. A set of the copies of this Agreement signed by all the parties shall be lodged with the Borrower and the Administrative Agent.

SECTION 9.9 Severability. Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

SECTION 9.10 Integration. This Agreement and the other Loan Documents represent the entire agreement of the Borrower, the Administrative Agent, the Issuing Bank and the Lenders with respect to the subject matter hereof and thereof, and there are no promises, undertakings, representations or warranties by the Administrative Agent, the Issuing Bank or any Lender relative to subject matter hereof not expressly set forth or referred to herein or in the other Loan Documents.

SECTION 9.11 GOVERNING LAW. THIS AGREEMENT AND THE RIGHTS AND OBLIGATIONS **OF THE PARTIES UNDER THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.**

SECTION 9.12 Submission To Jurisdiction; Waivers. Borrower hereby irrevocably and unconditionally:

(a) submits in any legal action or proceeding relating to this Agreement and the other Loan Documents to which it is a party, or for recognition and enforcement of any judgment in respect thereof, to the non-exclusive general jurisdiction of the courts of the State of New York, the courts of the United States of America for the Southern District of New York, and appellate courts from any thereof;

(b) consents that any such action or proceeding may be brought in such courts and waives any objection that it may now or hereafter have to the venue of any such action or proceeding in any such court or that such action or proceeding was brought in an inconvenient court and agrees not to plead or claim the same;

(c) agrees that service of process in any such action or proceeding may be effected by mailing a copy thereof by registered or certified mail (or any substantially similar form of mail), postage prepaid, to the Borrower, as the case may be, at its address set forth in Section 9.2 or at such other address of which the Administrative Agent shall have been notified pursuant thereto;

(d) agrees that nothing herein shall affect the right to effect service of process in any other manner permitted by law or shall limit the right to sue in any other jurisdiction; and

(e) waives, to the maximum extent not prohibited by law, any right it may have to claim or recover in any legal action or proceeding related to the Loan Documents any special, exemplary, punitive or consequential damages.

SECTION 9.13 Acknowledgments. Borrower hereby acknowledges that:

(a) it has been advised by counsel in the negotiation, execution and delivery of this Agreement and the other Loan Documents;

(b) neither the Administrative Agent, the Issuing Bank nor any Lender has any fiduciary relationship with or duty to the Borrower arising out of or in connection with this Agreement or any of the other Loan Documents, and the relationship between the Administrative Agent, the Issuing Bank and the Lenders, on one hand, and the Borrower, on the other hand, in connection herewith or therewith is solely that of debtor and creditor; and

(c) no joint venture is created hereby or by the other Loan Documents or otherwise exists by virtue of the transactions contemplated hereby among the Administrative Agent, the Issuing Bank and the Lenders or among the Borrower, the Issuing Bank and the Lenders.

SECTION 9.14 Confidentiality. Each of the Administrative Agent, the Issuing Bank and the Lenders agrees to keep confidential all non-public information provided to it by Borrower pursuant to this Agreement that is designated by Borrower as confidential; provided that nothing herein shall prevent the Administrative Agent, the Issuing Bank or any Lender from disclosing any such information (a) to the Administrative Agent, the Issuing Bank, any other Lender or any affiliate of any thereof, (b) to any Participant or Assignee (each, a "Transferee") or prospective Transferee that agrees to comply with the provisions of this Section, (c) to any of its employees, directors, agents, attorneys, accountants and other professional advisors, (d) to any financial institution that is a direct or indirect contractual counterparty in swap agreements or such contractual counterparty's professional advisor (so long as such contractual counterparty or professional advisor to such contractual counterparty agrees to be bound by the provisions of this Section), (e) upon the request or demand of any Governmental Authority having jurisdiction over it, (f) in response to any order of any court or other Governmental Authority or as may otherwise be required pursuant to any requirement of law, (g) in connection with any litigation or similar proceeding, (h) that has been publicly disclosed other than in breach of this Section, (i) to the National Association of Insurance Commissioners or any similar organization or any nationally

recognized rating agency that requires access to information about a Lender's investment portfolio in connection with ratings issued with respect to such Lender or (j) in connection with the exercise of any remedy hereunder or under any other Loan Document.

SECTION 9.15 Accounting Changes. In the event that any "Accounting Change" (as defined below) shall occur and such change results in a change in the method of calculation of financial covenants, standards or terms in this Agreement, then the Borrower and the Administrative Agent agree to enter into negotiations in order to amend such provisions of this Agreement so as to equitably reflect such Accounting Change with the desired result that the criteria for evaluating the financial condition of the Borrower shall be the same after such Accounting Change as if such Accounting Change had not been made. Until such time as such an amendment shall have been executed and delivered by the Borrower, the Administrative Agent and the Required Lenders, all financial covenants, standards and terms in this Agreement shall continue to be calculated or construed as if such Accounting Change had not occurred. "Accounting Change" refers to any change in accounting principles required by the promulgation of any rule, regulation, pronouncement or opinion by the Financial Accounting Standards Board of the American Institute of Certified Public Accountants or, if applicable, the SEC.

SECTION 9.16 Delivery of Lender Addenda. Each initial Lender shall become a party to this Agreement by delivering to the Administrative Agent a Lender Addendum duly executed by such Lender, the Borrower, the Issuing Bank and the Administrative Agent.

SECTION 9.17 WAIVERS OF JURY TRIAL. THE BORROWER, THE ADMINISTRATIVE AGENT, THE ISSUING BANK AND THE LENDERS HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE TRIAL BY JURY IN ANY LEGAL ACTION OR PROCEEDING RELATING TO THIS AGREEMENT OR ANY OTHER LOAN DOCUMENT AND FOR ANY COUNTERCLAIM THEREIN.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed and delivered by their proper and duly authorized officers as of the day and year first above written.

PG&E NATIONAL ENERGY GROUP, INC.

By: /s/ John R. Cooper

Name: John R. Cooper
Title: Senior Vice President

Amended and Restated Credit Agreement

THE CHASE MANHATTAN BANK,
as Issuing Bank

By: /s/ Thomas L. Casey

Name: Thomas L. Casey
Title: Vice President

Amended and Restated Credit Agreement

THE CHASE MANHATTAN BANK,
as Administrative Agent

By: /s/ Thomas L. Casey

Name: Thomas L. Casey
Title: Vice President

Amended and Restated Credit Agreement

THE CHASE MANHATTAN BANK,
as a Lender

By: /s/ Thomas L. Casey

Name: Thomas L. Casey
Title: Vice President

Amended and Restated Credit Agreement

DRESDNER BANK AG, NEW YORK AND GRAND CAYMAN BRANCHES,
as a Syndication Agent and as a Lender

By: /s/ Fredric Lammer

Name: Fredric Lammer
Title: Vice President

By: /s/ Fred C. Thurston

Name: Fred C. Thurston
Title: Vice President

Amended and Restated Credit Agreement

THE ROYAL BANK OF SCOTLAND PLC,
as a Syndication Agent and as a Lender

By: /s/ Brian J. McInnes

Name: Brian J. McInnes
Title: Senior Vice President

Amended and Restated Credit Agreement

BARCLAYS BANK PLC,
as a Documentation Agent and as a Lender

By: /s/ Sydney G. Dennis
---------- Name: Sydney G. Dennis
Title: Director

Amended and Restated Credit Agreement

WESTDEUTSCHE LANDESBANK GIROZENTALE, NEW YORK BRANCH, as a Documentation Agent and as a Lender

By: /s/ Jasjeet S. Sood

Name: Jasjeet S. Sood
Title: Managing Director and Head of Energy Group

By: /s/ Jarred Brenner

Name: Jarred Brenner
Title: Director

Amended and Restated Credit Agreement

ABN AMRO BANK N.V.

By: /s/ Jeffrey Dodd

Name: Jeffrey Dodd
Title: Group Vice President

By: /s/ Saad B. Qais

Name: Saad B. Qais
Title: Assistant Vice President

CITIBANK, N.A.

By: /s/ Sandip Sen

Name: Sandip Sen
Title: Managing Director

Amended and Restated Credit Agreement

CREDIT LYONNAIS NEW YORK BRANCH

By: /s/ Martin C. Livingston
---------- Name: Martin C. Livingston
Title: Vice President

Amended and Restated Credit Agreement

DG BANK DEUTSCHE GENOSSENSCHAFTSBANK AG

By: /s/ Mark Connelly

Name: Mark Connelly
Title: Vice President

By: /s/ William A. Klun

Name: William A. Klun
Title: Vice President

Amended and Restated Credit Agreement

SOCIETE GENERALE

By: /s/ David Bid

Name: David Bid
Title: Vice President

Amended and Restated Credit Agreement

BANK OF MONTREAL

By: /s/ Cahal B. Carmody

Name: Cahal B. Carmody
Title: Director

Amended and Restated Credit Agreement

THE BANK OF NOVA SCOTIA

By: /s/ Don DuPont

Name: Don DuPont
Title: Managing Director

Amended and Restated Credit Agreement

UBS AG, STAMFORD BRANCH

By: /s/ Wilfred V. Saint

Name: Wilfred V. Saint
Title: Associate Director
Banking Products Services, US

By: /s/ Lynne B. Alfarone

Name: Lynne B. Alfarone
Title: Associate Director
Banking Products Services, US

Amended and Restated Credit Agreement

FORTIS CAPITAL CORP.

By: /s/ John C. Preneta

Name: John C. Preneta
Title: Executive Vice President

By: /s/ David James

Name: David James
Title: Assistant Vice President

Amended and Restated Credit Agreement

TORONTO DOMINION (TEXAS), INC.

By: /s/ Carol Brandt
---------- Name: Carol Brandt
Title: Vice President

Amended and Restated Credit Agreement

FLEET NATIONAL BANK

By: /s/ Jill A. Calabrese Bain
---------- Name: Jill A. Calabrese Bain
Title: Vice President

Amended and Restated Credit Agreement

Exhibit 10.4

PG&E CORPORATION

SUPPLEMENTAL RETIREMENT SAVINGS PLAN

TABLE OF CONTENTS

		Page
1.	Purpose of the Plan	1
2.	Definitions	1
3.	Employer Contributions	3
4.	Eligible Employee Deferrals	5
5.	Investment Funds	6
6.	Accounting	7
7.	Distributions	8
8.	Distribution Due to Unforeseeable Emergency (Hardship Distribution)	10
9.	Domestic Relations Orders	11
10.	Vesting	11
11.	Administration of the Plan	11
12.	Funding	12
13.	Modification or Termination of Plan	12
14.	General Provisions	13
Appendix A		14

PG&E CORPORATION
SUPPLEMENTAL RETIREMENT SAVINGS PLAN

This is the controlling and definitive statement of the PG&E CORPORATION ("PG&E CORP") Supplemental Retirement Savings Plan (the "Plan"). Except as provided herein, the Plan is effective as of January 1, 2000, with respect to all individuals who were Eligible Employees as of such date. The Plan takes the place of and assumes existing benefits under the PG&E Corporation Deferred Compensation Plan for Officers, the PG&E Corporation Supplemental Executive Retirement Plan, the Savings Fund Plan Excess Benefit Arrangement of Pacific Gas and Electric Company, and any other non-qualified defined contribution retirement plan excess benefit plans, programs or practices maintained by any Participating Subsidiary of PG&E CORP. The Plan as originally adopted was effective January 1, 2000, for Eligible Employees of Pacific Gas and Electric Company and for Grandfathered Eligible Employees of PG&E CORP; it was effective January 1, 1999, for Eligible Employees of PG&E Generating Company; and it was effective January 1, 1997, for all other Eligible Employees of PG&E CORP. The Plan as amended herein is effective September 19, 2001.

1. Purpose of the Plan

The Plan is established and is maintained for the benefit of a select group of management and highly compensated employees of PG&E CORP and its Participating Subsidiaries in order to provide such employees with certain deferred compensation benefits. The Plan is an unfunded deferred compensation plan that is intended to qualify for the exemptions provided in Sections 201, 301, and 401 of ERISA.

2. Definitions

The following words and phrases shall have the following meanings unless a different meaning is plainly required by the context:

(a) " Basic Employer Contributions " shall mean the amounts credited to Eligible Employees' Accounts under the Plan by the Employers, in accordance with Section 3(c).

(b) " Board of Directors " shall mean the Board of Directors of PG&E CORP, as from time to time constituted.

(c) " Code " shall mean the Internal Revenue Code of 1986, as amended. Reference to a specific section of the Code shall include such section, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing, or superseding such section.

(d) " Committee " shall mean the Nominating and Compensation Committee of the Board, as it may be constituted from time to time.

(e) " Eligible Employee " shall mean an Employee who:

(1) Is an officer of PG&E CORP or any Participating Subsidiary and who is in Officer Band 5 or above; or

(2) Is a key employee of PG&E CORP or any Participating Subsidiary and who is designated by the Plan Administrator as eligible to participate in the Plan.

(f) " Eligible Employee's Account " or " Account " shall mean as to any Eligible Employee, the separate account maintained on the books of the Employer in accordance with Section 6(a) in order to reflect his or her interest under the Plan. Accounts shall be centrally administered by the Plan Administrator or its designee.

(g) " Employee " shall mean an individual who is treated in the records of an Employer as an employee of the Employer, who is not on an unpaid leave of absence, and/or who is not covered by a collective bargaining agreement; provided, however, such term shall not mean an individual who is a "leased employee" or who has entered into a written contract or agreement with an Employer which explicitly excludes such individual from participation in an Employer's benefit plans. The provisions of this definition shall govern, whether or not it is determined that an individual otherwise meets the definition of "common law" employee.

(h) " Employers " shall mean PG&E CORP and the Participating Subsidiaries designated by the Employee Benefit Committee of PG&E CORP. An initial list of the Participating Subsidiaries is contained in Appendix A to this Plan.

(i) " ERISA " shall mean the Employee Retirement Income Security Act of 1974, as amended. Reference to a specific section of ERISA shall include such section, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing, or superseding such section.

(j) " Grandfathered " shall mean an individual who was an Employee of Pacific Gas and Electric Company and who has become an Employee of PG&E CORP by reason of a transfer prior to January 1, 2000.

(k) " Investment Funds " shall mean (i) the PG&E CORP Phantom Stock Fund, (ii) the AA Utility Bond Fund, and (iii) the S&P 500 Index Fund. The Investment Funds shall be used for tracking phantom investment results under the Plan.

(l) " Matching Employer Contributions " shall mean the amounts credited to Eligible Employees' Accounts under the Plan by the Employers, in accordance with Section 3(b).

(m) " Participating Subsidiary " shall mean a United States-based subsidiary of PG&E CORP, which has been designated by the Employee Benefit Committee of PG&E CORP as a Participating Subsidiary under this Plan. At such times and under such conditions as the Committee may direct, one or more other subsidiaries of PG&E CORP may become Participating

Subsidiaries or a Participating Subsidiary may be withdrawn from the Plan.An initial list of the Participating Subsidiaries is contained in Appendix A to this Plan.

(n) " PG&E CORP " shall mean PG&E Corporation, a California corporation.

(o) " Plan " shall mean the PG&E Corporation Supplemental Retirement Savings Plan, as set forth in this instrument and as heretofore and hereafter amended from time to time.

(p) " Plan Year " shall mean the calendar year.

(q) " Retirement " or " Retire " shall mean an Eligible Employee's "separation from service" within the meaning of Section 401(k) of the Code, provided that the Eligible Employee is at least 55 years of age and has been employed by an Employer for at least five years.

(r) " RSP " shall mean, with respect to any Eligible Employee, the PG&E Corporation Retirement Savings Plan or any predecessor qualified retirement plan sponsored by PG&E CORP or any of its subsidiary companies.

(s) " Valuation Date " shall mean:

(1) For purposes of valuing Plan assets and Eligible Employees' Accounts for periodic reports and statements, the date as of which such reports or statements are made; and

(2) For purposes of determining the amount of assets actually distributed to the Eligible Employee, his or her beneficiary, or an Alternate Payee (or available for withdrawal), a date that shall not be more than seven business days prior to the date the check is issued to the Eligible Employee.

In any other case, the Valuation Date shall be the date designated by the Plan Administrator (in its discretion) or the date otherwise set forth in this Plan. In all cases, the Plan Administrator (in its discretion) may change the Valuation Date, on a uniform and nondiscriminatory basis, as is necessary or appropriate. Notwithstanding the foregoing, the Valuation Date shall occur at least annually.

3. Employer Contributions

(a) Matching Employer Contributions . Subject to the provisions of Section 13, the Eligible Employee's Account shall be credited for each Plan Year with a Matching Employer Contribution, calculated in the manner provided in Sections 3(a) (1), (2), and (3) below:

(1) First, an amount shall be calculated equal to the maximum matching contribution that would be made under the terms of the RSP, taking into account for such Plan Year the amount of pre-tax deferrals and after-tax contributions the Eligible Employee elected under the RSP. For purposes of this calculation, any amounts deferred under Subsection 4(a) of this Plan shall be treated as pre-tax deferrals under the RSP.

(2) The calculation made in accordance with this Section 3(a) (1) above shall be made without regard to any limitation on such amounts under the RSP resulting from the application of any of the limitations under Code Sections 401(m), 401(a)(17), or 415.

(3) The Employer Matching Contribution to be credited to the Account of an Eligible Employee for any Plan Year shall equal the amount calculated in accordance with Sections 3(a) (1) and (2) above, reduced by the amount of matching contribution made to such Eligible Employee's account for such Plan Year under the RSP.

(b) Crediting of Matching Employer Contributions . Matching Employer Contributions shall be calculated and credited to the Eligible Employee's Account as of the first business day of the calendar year following the Plan Year and shall be credited only if the Eligible Employee is an Employee on the last day of Plan Year for which the amounts are credited.

(c) Basic Employer Contributions . Subject to the provisions of Section 13, the Account of each Eligible Employee shall be credited for each Plan Year with a Basic Employer Contribution, calculated in the manner provided in Sections 3(c) (1), (2), and (3) below:

(1) First, an amount shall be calculated equal to the Basic Employer Contribution that would be made under the terms of the RSP, taking into account for such Plan Year the Eligible Employee's Covered Compensation under the RSP, before any deductions for compensation deferrals elected by such Eligible Employee under Subsection 4(a) of this Plan. For Eligible Employees as defined by Section 2(e)(1) of this Plan, compensation shall also reflect such Eligible Employee's Short-Term Incentive Plan awards.

(2) The calculation made in accordance with this Section 3(c)(1) above shall be made without regard to any limitation on such amounts under the RSP resulting from the application of any of the limitations under Code Sections 401(a)(4), 401(a)(17), or 415.

(3) The Employer Contribution to be credited to the Account of an Eligible Employee for any Plan Year shall equal the amount calculated in accordance with Sections 3(c)(1) and (2) above, reduced by the amount of Basic Employer Contributions made to such Eligible Employee's account for such Plan Year under the RSP.

(d) Crediting of Basic Employer Contributions . The Employer Contribution attributable to an Eligible Employee's Short Term Incentive Plan award shall be credited to an Eligible Employee's Account as of the first business day of the month following the date on which the Short-Term Incentive Plan award is paid. All other Employer Contributions made in respect of an Eligible Employee shall be credited to the Eligible Employee's Account as of the first business day of the calendar year following the Plan Year and shall be credited only if the Eligible Employee is an Employee on the last day of the Plan Year for which the amounts are credited.

(e) FICA Taxes . Each Eligible Employee shall be responsible for FICA taxes on amounts credited to his or her Account under Sections 3 and 4(d).

4. Eligible Employee Deferrals

(a) Amount of Deferral . An Eligible Employee may defer (i) 5 percent to 50 percent of his or her annual salary; and (ii) all or part of his or her Short Term Incentive Plan awards, Long-Term Incentive Plan (LTIP) awards (other than stock options), Perquisite Allowances, and any other special payments, awards, or bonuses as authorized by the Plan Administrator.

(b) Credits to Accounts . Salary deferrals shall be credited to an Eligible Employee's Account as of each payroll period. All other deferrals attributable to allowances, awards, bonuses, and other payments shall be credited as of the date that they otherwise would have been paid.

(c) Deferral Election . An Eligible Employee must file an election form with the Plan Administrator which indicates the percentage of salary and applicable pay periods, and the amount of any awards, allowances, payments, and bonuses to be deferred under the Plan. Notwithstanding the foregoing, upon first becoming an Eligible Employee, an election to defer shall be effective for the month following the filing of a Deferral Election Form, provided said Form is filed within 60 days following the date when the employee first becomes an Eligible Employee.

(d) Deferral of Special Incentive Stock Ownership Premiums . All of an Eligible Employee's Special Incentive Stock Ownership Premiums are automatically deferred to the Plan immediately upon grant and converted into units in the PG&E CORP Phantom Stock Fund. The units attributable to Special Incentive Stock Ownership Premiums and any additional units resulting from the conversion of dividend equivalents thereon remain unvested until the earlier of the third anniversary of the date on which the Special Incentive Stock Ownership Premiums are credited to an Eligible Employee's account (provided the Eligible Employee continues to be employed on such date), death, disability, or retirement of the participant, or upon a Change in Control as defined in the LTIP. (The term "disability" shall, for purposes of the Plan, have the same meaning as in Section 22(e)(3) of the Internal Revenue Code.) Unvested units attributable to Special Incentive Stock Ownership Premiums and any additional units resulting from the conversion of dividend equivalents thereon shall be forfeited upon termination of the Eligible Employee's employment unless otherwise provided in the PG&E Corporation Officer Severance Policy, or if an Eligible Employee's stock ownership falls below the levels set forth in the Executive Stock Ownership Program.

5. Investment Funds

(a) Although no assets will be segregated or otherwise set aside with respect to an Eligible Employee's Account, the amount that is ultimately payable to the Eligible Employee with respect to such Account shall be determined as if such Account had been invested in some or all of the Investment Funds. The Plan Administrator, in its sole discretion, shall adopt (and modify from time to time) such rules and procedures as it deems necessary or appropriate to implement the deemed investment of the Eligible Employees' Accounts. Such procedures generally shall provide that an Eligible Employee's Account shall be deemed to be invested among the three Investment Funds in the manner elected by the Eligible Employee in such percentages and manner as prescribed by the Plan Administrator. In the event no election has been made by the Eligible Employee, such Account will be deemed to be invested in the AA Utility Bond Fund. Eligible Employees shall be able to reallocate their Accounts between the Investment Funds and reallocate amounts newly credited to their Accounts at such time and in such manner as the Plan Administrator shall prescribe. Anything to the contrary herein notwithstanding, an Eligible Employee may not reallocate Account balances between Investment Funds if such reallocation would result in a non-exempt Discretionary Transaction as defined in Rule 16b-3 of the Securities Exchange Act of 1934, as amended, or any successor to Rule 16b-3, as in effect when the reallocation is requested.

(1) AA Utility Bond Fund. Interest shall be credited daily on the amounts invested in the AA Utility Bond Fund. Such interest shall be at a rate equal to the AA Utility Bond Yield reported in Moody's Public Utility , published in the issue of Moody's Investors Service immediately preceding the day on which the interest is to be credited. Such interest shall become a part of the Eligible Employee's Account and shall be paid at the same time or times as the balance of the Eligible Employee's Account.

(2) PG&E CORP Phantom Stock Fund. Amounts credited to the PG&E CORP Phantom Stock Fund shall be converted into units (including fractions computed to three decimal places) each representing a share of PG&E CORP common stock. The value of a unit for purposes of determining the number of units to credit upon initial allocation or upon reallocation from another Investment Fund, and for determining the dollar value of the aggregate number of units to be reallocated from the PG&E CORP Phantom Stock Fund to another Investment Fund and for distributions from the Plan, shall be the closing price of a share of PG&E CORP common stock as traded on the New York Stock Exchange on the date that (i) amounts are credited to an Eligible Employee's Account in the PG&E CORP Phantom Stock Fund, or (ii) the Plan Administrator receives a reallocation request, in the case of reallocations. If such credit or reallocation occurs after close of the New York Stock Exchange on that day, the price shall be based on the closing price of a share of PG&E CORP common stock on the next day on which such shares are traded on the New York Stock Exchange. Thereafter, the value of a unit shall fluctuate in accordance with the closing price of PG&E CORP common stock on the New York Stock Exchange. Each time that PG&E CORP pays a dividend on its common stock, an amount equal to such dividend payable with respect to each share of PG&E CORP common stock, multiplied by the number of units credited to an Eligible Employee's

Account, shall be credited to the Eligible Employee's Account and converted into additional units. The number of additional units shall be calculated by dividing the aggregate amount of credited dividends, i.e. the dividend multiplied by the number of units credited to the Eligible Employee's Account as of the dividend record date, by the closing price of a share of PG&E CORP common stock on the New York Stock Exchange on the dividend payment date. If, after the record date but before the dividend payment date, an Eligible Employee's balance in the PG&E CORP Phantom Stock Fund has been reallocated to another Investment Fund(s) or has been paid to the Eligible Employee or to the Eligible Employee's beneficiary, other than pursuant to an election under Sections 7(c)(2) or 8, then an amount equal to the aggregated dividend shall be credited to the Eligible Employee's Account in such other Investment Fund(s) or paid directly to the Eligible Employee or the Eligible Employee's beneficiary, whichever is applicable.

(3) S&P 500 Index Fund. Amounts credited to the S&P 500 Index Fund shall be converted into units each representing a Large Company Stock Fund (LCSF) unit held in the RSP on the date of allocation. Thereafter, the value of a unit held in the S&P Index Fund shall bedetermined in the same manner as the value of a LCSF unit under Section 18 of the RSP.

6. Accounting

(a) Eligible Employees' Accounts . At the direction of the Plan Administrator, there shall be established and maintained on the books of the Employer, a separate account for each Eligible Employee in order to reflect his or her interest under the Plan.

(b) Investment Earnings . Each Eligible Employee's Account shall initially reflect the value of his or her Account's interest in each of the Investment Funds, deemed acquired with the amounts credited thereto. Each Eligible Employee's Account shall also be credited (or debited) as of the end of each day with the net appreciation (or depreciation), earnings and gains (or losses) with respect to the investments deemed made by his or her Account. Any such net earnings or gains deemed realized with respect to any investment of any Eligible Employee's Account shall be deemed reinvested in additional amounts of the same investment and credited to the Eligible Employee's Account.

(c) Accounting Methods . The accounting methods or formulae to be used under the Plan for the purpose of maintaining the Eligible Employees' Accounts shall be determined by the Plan Administrator. The accounting methods or formulae selected by the Plan Administrator may be revised from time to time but shall conform to the extent practicable with the accounting methods used under the Applicable Plan.

(d) Valuations and Reports . The fair market value of each Eligible Employee's Account shall be determined as of each Valuation Date. In making such determinations and in crediting net deemed earnings and gains (or losses) in the Investment Funds to the Eligible Employees' Accounts, the Plan Administrator (in its discretion) may employ such accounting methods as the Plan Administrator (in its discretion) may deem appropriate in order to fairly reflect the fair market values of the Investment Funds and each Eligible Employee's Account. For this purpose, the Plan Administrator may rely upon information provided by the Plan Administrator or other persons believed by the Plan Administrator to be competent.

(e) Statements of Eligible Employee's Accounts . Each Eligible Employee shall be furnished with periodic statements of his or her interest in the Plan, at least annually.

7. Distributions

(a) Distribution of Account Balances . Unless the Eligible Employee has elected otherwise under this Section 7, distribution of the balance credited to an Eligible Employee's Account shall be made in a single sum in the January of the year following Retirement or termination of service:

(1) In the case of an Alternate Payee (as defined in Section 9(a)), distribution shall be made as directed in a domestic relations order which the Plan Administrator determines is a QDRO (as defined in Section 9(a)), but only as to the portion of the Eligible Employee's Account which the QDRO states is payable to the Alternate Payee.

(2) Any provisions of the Plan notwithstanding distribution of account balances must commence no later than in the January following the year which the Eligible Employee reaches age 72.

(b) Installment Distributions . In lieu of a single sum payment, an Eligible Employee whose Account value (exclusive of Special Incentive Stock Ownership Premiums) is at least $5,000 may elect in writing and file with the Plan Administrator an election that payment of amounts credited to the Eligible Employee's Account be made in a specified number of approximately equal annual installments (not in excess of 10). However, if during the installment payment period the Account balance, exclusive of Special Incentive Stock Ownership Premiums, is less than $5,000, the value of the remaining installments shall be paid as a lump sum. All installment payments will be made during the month of January.

(c) Early Distributions . By filing an irrevocable election with the Plan Administrator, an Eligible Employee may elect to commence distribution of full or partial payment at any time other than Retirement or termination, provided that:

(1) such election is made at least one year prior to the Retirement or termination of the Eligible Employee and does not provide for the receipt of such amounts earlier than one year from the date of the election; or

(2) the Eligible Employee elects to forfeit 10 percent of the value of the requested distribution, valued as of the new date for distribution of such Account funds, and such Eligible Employee shall not be permitted to make future deferrals for 24 months following such distribution.

All early distributions elected pursuant to Section 7(c)(1) must be made during the month of January.

(d) Death Distributions . If an Eligible Employee dies before the entire balance of his or her Account has been distributed (whether or not the Eligible Employee had previously terminated employment and whether or not installment payments had previously commenced), the remaining balance of the Eligible Employee's Account shall be distributed to the beneficiary designated or otherwise determined in accordance with Section 7(g), as soon as practicable after the date of death.

(e) Special Incentive Stock Ownership Premiums . Distributions attributable to Special Incentive Stock Ownership Premiums shall only be made in January following the year in which an Eligible Employee terminates employment, Retires, or dies, and shall only be made in the form of one or more certificates for the number of vested Special Incentive Stock Ownership Premium units, rounded down to the nearest whole share.

(f) Effect of Change in Eligible Employee Status . If an Eligible Employee ceases to be an Eligible Employee, the balance credited to his or her Account shall continue to be credited (or debited) with appreciation, depreciation, earnings, gains or losses under the terms of the Plan and shall be distributed to him or her at the time and in the manner set forth in this Section 7; provided, however, that if an Eligible Employee terminates employment with an Employer other than by reason of Retirement, the entire balance credited to his or her Account shall be distributed in a lump sum cash payment in January of the year following the year of termination of employment. Anything to the contrary notwithstanding, the Plan Administrator, in its sole discretion, may authorize an accelerated distribution of the balance credited to his or her Account in the form of a lump sum cash payment as of any earlier date.

(g) Payments to Incompetents . If any individual to whom a benefit is payable under the Plan is a minor or if the Plan Administrator determines that any individual to whom a benefit is payable under the Plan is incompetent to receive such payment or to give a valid release therefor, payment shall be made to the guardian, committee, or other representative of the estate of such individual which has been duly appointed by a court of competent jurisdiction. If no guardian, committee, or other representative has been appointed, payment may be made to any person as custodian for such individual under the California Uniform Transfers to Minors Act (or similar law of another state) or may be made to or applied to or for the benefit of the minor or incompetent, the incompetent's spouse, children or other dependents, the institution or persons maintaining the minor or incompetent, or any of them, in such proportions as the Plan Administrator from time to time shall determine; and the release of the person or

institution receiving the payment shall be a valid and complete discharge of any liability of PG&E CORP with respect to any benefit so paid.

(h) Beneficiary Designations . Each Eligible Employee may designate, in a signed writing delivered to the Plan Administrator, on such form as it may prescribe, one or more beneficiaries to receive any distribution which may become payable under the Plan as the result of the Eligible Employee's death. An Eligible Employee may designate different beneficiaries at any time by delivering a new designation in like manner. Any designation shall become effective only upon its receipt by the Plan Administrator, and the last effective designation received by the Plan Administrator shall supersede all prior designations. If an Eligible Employee dies without having designated a beneficiary or if no beneficiary survives the Eligible Employee, the Eligible Employee's Account shall be payable to the beneficiary or beneficiaries designated or otherwise determined under the RSP.

(i) Undistributable Accounts . Each Eligible Employee and (in the event of death) his or her beneficiary shall keep the Plan Administrator advised of his or her current address. If the Plan Administrator is unable to locate the Eligible Employee or beneficiary to whom an Eligible Employee's Account is payable under this Section 7, the Eligible Employee's Account shall be frozen as of the date on which distribution would have been completed in accordance with this Section 7, and no further appreciation, depreciation, earnings, gains or losses shall be credited (or debited) thereto. PG&E CORP shall have the right to assign or transfer the liability for payment of any undistributable Account to the Eligible Employee's former Employer (or any successor thereto).

(j) Plan Administrator Discretion . Within the specific time periods described in this Section 7, the Plan Administrator shall have sole discretion to determine the specific timing of the payment of any Account balance under the Plan.

8. Distribution Due to Unforeseeable Emergency (Hardship Distribution)

A participant may request a distribution due to an unforseeable emergency by submitting a written request to the Plan Administrator. The Plan Administrator shall have the authority to require such evidence as it deems necessary to determine if a distribution is warranted. If an application for a hardship distribution due to an unforeseeable emergency is approved, the distribution shall be payable in a method determined by the Plan Administrator as soon as possible after approval of such distribution. After receipt of a payment requested due to an unforeseeable emergency, a participant may not make additional deferrals during the remainder of the Plan Year in which the recipient received the payment. A participant who has commenced receiving installment payments under the Plan may request acceleration of such payments in the event of an unforeseeable emergency. The Administrator may permit accelerated payments to the extent such accelerated payment does not exceed the amount necessary to meet the emergency.

9. Domestic Relations Orders

(a) Qualified Domestic Relations Orders . The Plan Administrator shall establish written procedures for determining whether a domestic relations order purporting to dispose of any portion of an Eligible Employee's Account is a qualified domestic relations order (within the meaning of Section 414(p) of the Code) (a " QDRO ").

(1) No Payment Unless a QDRO. No payment shall be made to any person designated in a domestic relations order (an " Alternate Payee ") until the Plan Administrator (or a court of competent jurisdiction reversing an initial adverse determination by the Plan Administrator) determines that the order is a QDRO. Payment shall be made to each Alternate Payee as specified in the QDRO.

(2) Time of Payment. Payment may be made to an Alternate Payee in the form of a lump sum, at the time specified in the QDRO, but no earlier than as soon as practicable following the date the QDRO determination is made.

(3) Hold Procedures. Notwithstanding any contrary Plan provision, prior to the receipt of a domestic relations order, the Plan Administrator may, in its sole discretion, place a hold upon all or a portion of an Eligible Employee's Account for a reasonable period of time (as determined by the Plan Administrator) if the Plan Administrator receives notice that (a) a domestic relations order is being sought by the Eligible Employee, his or her spouse, former spouse, child or other dependent, and (b) the Eligible Employee's Account is a source of the payment under such domestic relations order. For purposes of this Section 9(a)(3), a " hold " means that no withdrawals, distributions, or investment transfers may be made with respect to an Eligible Employee's Account. If the Plan Administrator places a hold upon an Eligible Employee's Account pursuant to this Section 9(a)(3), it shall inform the Eligible Employee of such fact.

10. Vesting

Except as provided in Section 4(d), an Eligible Employee's interest in his or her Account at all times shall be 100 percent vested and nonforfeitable.

11. Administration of the Plan

(a) Plan Administrator . The Employee Benefit Committee of PG&E CORP is hereby designated as the administrator of the Plan (within the meaning of Section 3(16)(A) of ERISA). The Plan Administrator delegates to the Senior Human Resource Officer for PG&E CORP, or his or her designee, the authority to carry out all duties and responsibilities of the Plan Administrator under the Plan. The Plan Administrator shall have the authority to control and manage the operation and administration of the Plan.

(b) Powers of Plan Administrator . The Plan Administrator shall have all discretion and powers necessary to supervise the administration of the Plan and to control its operation in accordance with its terms, including, but not by way of limitation, the power to interpret the provisions of the Plan and to determine, in its sole discretion, any question arising under, or in connection with the administration or operation of, the Plan.

(c) Decisions of Plan Administrator . All decisions of the Plan Administrator and any action taken by it in respect of the Plan and within the powers granted to it under the Plan shall be conclusive and binding on all persons and shall be given the maximum deference permitted by law.

12. Funding

All amounts credited to an Eligible Employee's Account under the Plan shall continue for all purposes to be a part of the general assets of PG&E CORP. The interest of the Eligible Employee in his or her Account, including his or her right to distribution thereof, shall be an unsecured claim against the general assets of PG&E CORP. While PG&E CORP may choose to invest a portion of its general assets in investments identical or similar to those selected by Eligible Employees for purposes of determining the amounts to be credited (or debited) to their Accounts, nothing contained in the Plan shall give any Eligible Employee or beneficiary any interest in or claim against any specific assets of PG&E CORP.

13. Modification or Termination of Plan

(a) Employers' Obligations Limited . The Plan is voluntary on the part of the Employers, and the Employers do not guarantee to continue the Plan. PG&E CORP at any time may, by appropriate amendment of the Plan, suspend Matching Employer Contributions and/or Basic Employer Contributions or may discontinue Matching Employer Contributions and/or Basic Employer Contributions, with or without cause.

(b) Right to Amend or Terminate . The Board of Directors, acting through its Nominating and Compensation Committee, reserves the right to alter, amend, or terminate the Plan, or any part thereof, in such manner as it may determine, for any reason whatsoever.

(1) Limitations. Any alteration, amendment, or termination shall take effect upon the date indicated in the document embodying such alteration, amendment, or termination, provided that no such alteration or amendment shall divest any portion of an Account that is then vested under the Plan.

(c) Effect of Termination . If the Plan is terminated, the balances credited to the Accounts of the Eligible Employees affected by such termination shall be distributed to them at the time and in the manner set forth in Section 7; provided, however, that the Plan Administrator, in its sole discretion, may authorize accelerated distribution of Eligible Employees' Accounts as of any earlier date.

14. General Provisions

(a) Inalienability . Except to the extent otherwise directed by a domestic relations order which the Plan Administrator determines is a QDRO (as defined in Section 9(a) or mandated by applicable law, in no event may either an Eligible Employee, a former Eligible Employee or his or her spouse, beneficiary or estate sell, transfer, anticipate, assign, hypothecate, or otherwise dispose of any right or interest under the Plan; and such rights and interests shall not at any time be subject to the claims of creditors nor be liable to attachment, execution, or other legal process.

(b) Rights and Duties . Neither the Employers nor the Plan Administrator shall be subject to any liability or duty under the Plan except as expressly provided in the Plan, or for any action taken, omitted, or suffered in good faith.

(c) No Enlargement of Employment Rights . Neither the establishment or maintenance of the Plan, the making of any Matching Employer Contributions, nor any action of any Employer or Plan Administrator, shall be held or construed to confer upon any individual any right to be continued as an Employee nor, upon dismissal, any right or interest in any specific assets of the Employers other than as provided in the Plan. Each Employer expressly reserves the right to discharge any Employee at any time, with or without cause or advance notice.

(d) Apportionment of Costs and Duties . All acts required of the Employers under the Plan may be performed by PG&E CORP for itself and its Participating Subsidiaries, and the costs of the Plan may be equitably apportioned by the Plan Administrator among PG&E CORP and the other Employers. Whenever an Employer is permitted or required under the terms of the Plan to do or perform any act, matter or thing, it shall be done and performed by any officer or employee of the Employer who is thereunto duly authorized by the board of directors of the Employer.

(e) Applicable Law . The provisions of the Plan shall be construed, administered, and enforced in accordance with the laws of the State of California and, to the extent applicable, ERISA.

(f) Severability . If any provision of the Plan is held invalid or unenforceable, its invalidity or unenforceability shall not affect any other provisions of the Plan, and the Plan shall be construed and enforced as if such provision had not been included.

(g) Captions . The captions contained in and the table of contents prefixed to the Plan are inserted only as a matter of convenience and for reference and in no way define, limit, enlarge, or describe the scope or intent of the Plan nor in any way shall affect the construction of any provision of the Plan.

APPENDIX A

PARTICIPATING SUBSIDIARIES

Participating Subsidiaries as of January 1, 1997

– PG&E Gas Transmission Corporation
– PG&E Gas Transmission, Texas Corporation
– PG&E Gas Transmission TECO, Inc.
– PG&E Energy Trading–Gas Corporation
– PG&E Energy Services Corporation
– And the U.S. subsidiaries of each of the above-named corporations.

Additional Participating Subsidiaries as of January 1, 1998

– PG&E Corporation
– Pacific Gas and Electric Company
– PG&E Generating Company
– PG&E Corporation Support Services, Inc.
– And the U.S. subsidiaries of each of the above-named corporations.

EXHIBIT 10.16

SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
OF
THE PACIFIC GAS AND ELECTRIC COMPANY

This is the controlling and definitive statement of the Supplemental Executive Retirement Plan ("PLAN" [1]) for ELIGIBLE EMPLOYEES of Pacific Gas and Electric Company ("COMPANY") and such other companies, affiliates, subsidiaries, or associations as the BOARD OF DIRECTORS may designate from time to time. The PLAN was first adopted by the BOARD OF DIRECTORS in 1984 and was effective January 1, 1985. It has since been amended from time to time. Except as expressly stated by any amendment to this PLAN, benefits of ELIGIBLE EMPLOYEES who retire, terminate from employment, or cease to be ELIGIBLE EMPLOYEES prior to the effective date of any amendment shall not be affected by any such amendment. The amended PLAN as contained herein is effective September 19, 2001.

ARTICLE I

DEFINITIONS

1.01 Basic SERP Benefit shall mean the benefit described in Section 2.01.

1.02 Beneficiary shall mean the person, persons, or entity designated by the ELIGIBLE EMPLOYEE to receive payments under any optional form of benefit elected pursuant to Section 2.03 c. or Section 2.03 d., payable or owed but unpaid at the time of the ELIGIBLE EMPLOYEE's death. An ELIGIBLE EMPLOYEE shall designate a BENEFICIARY on a form provided by the PLAN ADMINISTRATOR and kept on file in the PLAN ADMINISTRATOR's office. An ELIGIBLE EMPLOYEE may change a BENEFICIARY at any time by filing a new beneficiary form with the PLAN ADMINISTRATOR.

1.03 Board or Board of Directors shall mean the BOARD OF DIRECTORS of the COMPANY or, when appropriate, any committee of the BOARD which has been delegated the authority to take action with respect to the PLAN.

1.04 Company shall mean the Pacific Gas and Electric Company, a California corporation.

1.05 Eligible Employee shall mean (1) employees of the COMPANY, or (2) with respect to PG&E Corporation and PG&E Corporation Support Services, Inc., employees who were

1 Words in all capitals are defined in Article I.

transferred to PG&E Corporation or PG&E Corporation Support Services, Inc., from the COMPANY, (3) who are officers in Officer Bands I-V, and (4) such other employees of the COMPANY, or such other companies, affiliates, subsidiaries, or associations, as may be designated by the Chairman of the Board of the COMPANY.

1.06 STIP Payment shall mean amounts received by an ELIGIBLE EMPLOYEE under the Short-Term Incentive Plan maintained by PG&E Corporation.

1.07 Plan shall mean the Supplemental Executive Retirement Plan ("SERP") as set forth herein and as may be amended from time to time.

1.08 Plan Administrator shall mean the Employee Benefit Finance Committee or such individual or individuals as that Committee may appoint to handle the day-to-day affairs of the PLAN.

1.09 Retirement Plan shall mean the Pacific Gas and Electric Company Retirement Plan for Management Employees.

1.10 Salary shall mean the base salary received by an ELIGIBLE EMPLOYEE. SALARY shall not include amounts received by an employee after such employee ceases to be an ELIGIBLE EMPLOYEE. For purposes of calculating benefits under the PLAN, SALARY shall not be reduced to reflect amounts which have been deferred under the PG&E Corporation Supplemental Retirement Savings Plan.

1.11 Service shall mean "credited service" as that term is defined in the RETIREMENT PLAN or, if the Nominating and Compensation Committee of the BOARD OF DIRECTORS has granted an adjusted service date for an ELIGIBLE EMPLOYEE, "credited service" as calculated from such adjusted service date. In no event, however, shall SERVICE include periods of time after which an officer has ceased to be an ELIGIBLE EMPLOYEE.

ARTICLE II

SERP BENEFITS

2.01 The BASIC SERP BENEFIT payable from the PLAN shall be a monthly annuity commencing on the first of the month following the month in which the ELIGIBLE EMPLOYEE (i) attains his 65th birthday or (ii) ceases to be an employee of the COMPANY, whichever is later. The monthly amount of the BASIC SERP BENEFIT shall be equal to the product of:

1.7% x [average of three highest calendar years' combination of SALARY and STIP PAYMENT for the last ten years of SERVICE] x SERVICE x 1/12.

In computing a year's combination of SALARY and STIP PAYMENT, the year's amount shall be the sum of the SALARY and STIP PAYMENT, if any, paid or payable in the same calendar year. If an ELIGIBLE EMPLOYEE has fewer than three years' SALARY, the average

shall be the combination of SALARY and STIP PAYMENT for such shorter time, divided by the number of years and partial years during which such employee was an ELIGIBLE EMPLOYEE.

The BASIC SERP BENEFIT is further reduced by any amounts paid or payable from the RETIREMENT PLAN, calculated before adjustments for marital or joint pension option elections.

2.02 For ELIGIBLE EMPLOYEES of the COMPANY, PG&E Corporation, or PG&E Corporation Support Services, Inc., who transfer from any of said companies to another subsidiary or affiliate, the principles of Section 10 of the RETIREMENT PLAN shall govern the calculation of benefits under this PLAN. An ELIGIBLE EMPLOYEE who ceases to be an employee of the COMPANY and who is also not employed by any of its subsidiaries, affiliates, or related associations shall be entitled to receive a benefit payable from the PLAN at any time after his 55th birthday. The amount of the benefit payable shall be reduced by the appropriate age and service factors contained in the RETIREMENT PLAN applicable to such employee. For such calculations, the service factor shall be SERVICE as defined in the PLAN.

In computing amounts payable from the RETIREMENT PLAN as an offset to the benefit payable from this PLAN, the RETIREMENT PLAN benefit shall be calculated as though the ELIGIBLE EMPLOYEE elected to receive a pension from the RETIREMENT PLAN commencing on the same date as benefits from this PLAN.

2.03 An ELIGIBLE EMPLOYEE may elect to have his BASIC SERP BENEFIT paid in any one of the following forms:

a. BASIC SERP BENEFIT, or a reduced BASIC SERP BENEFIT as calculated under Section 2.02, paid as a monthly annuity for the life of the ELIGIBLE EMPLOYEE with no survivor's benefit.

b. A monthly annuity payable for the life of the ELIGIBLE EMPLOYEE with a survivor's option payable to the ELIGIBLE EMPLOYEE's joint annuitant beginning on the first of the month following the ELIGIBLE EMPLOYEE'S death. The factors to be applied to reduce the BASIC SERP BENEFIT to provide for a survivor's benefit shall be the factors which are contained in the RETIREMENT PLAN and which are appropriate given the type of joint pension elected and the ages and marital status of the joint annuitants.

c. A five-year or ten-year certain annuity, with equal annual installment payments beginning on January 1 of the year following the year in which payments of the BASIC SERP BENEFIT would otherwise have commenced and continuing every January 1 thereafter until all payments are made. In determining the amount of the annuity payments, the present value of the BASIC SERP BENEFIT shall be computed using the appropriate mortality factors contained in the RETIREMENT PLAN for single life annuities and the interest rate set by the Pension Benefit Guaranty Corporation as of the first day of the year in which annuity payments begin.

d. A lump sum payment of the actuarial present value of the BASIC SERP BENEFIT which would have been payable to the ELIGIBLE EMPLOYEE under Section 2.03 a. In determining the actuarial present value of the BASIC SERP BENEFIT, the PLAN ADMINISTRATOR shall apply the appropriate mortality factors used in calculating lump sum payments under the RETIREMENT PLAN for single life annuities and the interest rate set by the Pension Benefit Guaranty Corporation as of the first day of the year in which the lump sum payment is made.

2.04 Annuities payable to an ELIGIBLE EMPLOYEE who is receiving a (i) BASIC SERP BENEFIT, (ii) a BASIC SERP BENEFIT reduced to provide a survivor's benefit to a joint annuitant, or (iii) a joint annuitant who is receiving a survivor's benefit shall be decreased by any additional amounts which can be paid from the RETIREMENT PLAN where such additional amounts are due to increases in the limits placed on benefits payable from qualified pension plans under Section 4l5 of the Internal Revenue Code. The amount of any such decrease shall be adjusted to reflect the type of pension elected by an ELIGIBLE EMPLOYEE under the RETIREMENT PLAN and this PLAN. Decreases under this Section 2.04 shall not be applied to decrease benefits payable under the lump sum or the five-year or ten-year certain annuity options.

ARTICLE III

DEATH BENEFITS

3.01 For an ELIGIBLE EMPLOYEE who has elected to receive his PLAN benefits in one of the optional forms described in Section 2.03 c. or 2.03 d. and who dies before receiving the total number of payments selected under the optional form of benefit, the PLAN ADMINISTRATOR shall continue to make the scheduled benefit payments to the BENEFICIARY designated by the ELIGIBLE EMPLOYEE. If the ELIGIBLE EMPLOYEE has failed to designate a BENEFICIARY or if there is no designated BENEFICIARY surviving at the time of the ELIGIBLE EMPLOYEE'S death, the PLAN ADMINISTRATOR shall make the remaining payments to the estate of the ELIGIBLE EMPLOYEE.

3.02 In the event that an ELIGIBLE EMPLOYEE who has accrued a benefit under this PLAN dies prior to the date that a BASIC SERP BENEFIT would otherwise commence and the ELIGIBLE EMPLOYEE is married at the time of the ELIGIBLE EMPLOYEE's death, the PLAN ADMINISTRATOR shall pay a spouse's benefit to the ELIGIBLE EMPLOYEE's surviving spouse:

a. If the sum of the age and SERVICE of the ELIGIBLE EMPLOYEE at the time of death equaled 70 (69.5 or more is rounded to 70) or if the ELIGIBLE EMPLOYEE was age 55 at the time of death, the spouse's benefit shall be a monthly annuity commencing on the first of the month following the month in which the ELIGIBLE EMPLOYEE dies and shall be payable for the life of the surviving spouse. The amount of the monthly benefit shall be one-half of the

monthly BASIC SERP BENEFIT which would have been paid to the ELIGIBLE EMPLOYEE calculated:

1) as if he had elected to receive a BASIC SERP BENEFIT, without survivor's option;

2) the monthly annuity starting date was the first of the month following the month in which the ELIGIBLE EMPLOYEE died; and

3) without the application of early retirement reduction factors.

b. If the ELIGIBLE EMPLOYEE is less than 55 years of age or had fewer than 70 points (as calculated under Section 3.02(a)) at the time of death, the surviving spouse will be entitled to receive a monthly annuity commencing on the first of the month following the month in which the ELIGIBLE EMPLOYEE would have become age 55 if he had survived. The amount of the monthly annuity payable to the surviving spouse shall be equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the ELIGIBLE EMPLOYEE had terminated employment at the date of death, 2) had lived until age 55, 3) had begun to receive PENSION payments, and 4) had subsequently died.

c. If a former ELIGIBLE EMPLOYEE was age 55 or older at the time of his death and not yet receiving a SERP BENEFIT under the PLAN, the surviving spouse will be entitled to receive a monthly annuity in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if the former ELIGIBLE EMPLOYEE had begun receiving the converted SERP BENEFIT immediately prior to his death.

d. If a former ELIGIBLE EMPLOYEE was younger than age 55 or had fewer than 70 points (as calculated under Section 3.02(a)) at the time of his death, the surviving spouse will be entitled to receive a monthly annuity in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the former ELIGIBLE EMPLOYEE had survived until age 55, 2) had begun receiving the converted SERP BENEFIT, and 3) had subsequently died.

3.03 A surviving spouse who is entitled to receive a spouse's benefit under Section 3.02 shall not be entitled to receive any other benefit under the PLAN.

ARTICLE IV

ADMINISTRATIVE PROVISIONS

4.01 Administration . The PLAN shall be administered by the PLAN ADMINISTRATOR who shall have the authority to interpret the PLAN and make such rules as it deems appropriate. The PLAN ADMINISTRATOR shall have the duty and responsibility of maintaining records, making the requisite calculations, and disbursing payments hereunder. The PLAN ADMINISTRATOR's interpretations, determinations, rules, and calculations shall be final and binding on all persons and parties concerned.

4.02 Amendment and Termination . The COMPANY may amend or terminate the PLAN at any time, provided, however, that no such amendment or termination shall adversely affect an accrued benefit which an ELIGIBLE EMPLOYEE has earned prior to the date of such amendment or termination, nor shall any amendment or termination adversely affect a benefit which is being provided to an ELIGIBLE EMPLOYEE, surviving spouse, joint annuitant, or beneficiary under Article II or Article III on the date of such amendment or termination. Anything in this Section 4.02 to the contrary notwithstanding, the COMPANY may reduce or terminate any benefit to which an ELIGIBLE EMPLOYEE, surviving spouse, joint annuitant, or BENEFICIARY is or may become entitled provided that such ELIGIBLE EMPLOYEE, surviving spouse, joint annuitant, or BENEFICIARY is or becomes entitled to an amount equal to such benefit under another plan, practice, or arrangement of the COMPANY.

4.03 Nonassignability of Benefits . The benefits payable under this PLAN or the right to receive future benefits under this PLAN may not be anticipated, alienated, pledged, encumbered, or subject to any charge or legal process, and if any attempt is made to do so, or a person eligible for any benefits becomes bankrupt, the interest under the PLAN of the person affected may be terminated by the PLAN ADMINISTRATOR which, in its sole discretion, may cause the same to be held if applied for the benefit of one or more of the dependents of such person or make any other disposition of such benefits that it deems appropriate.

4.04 Nonguarantee of Employment . Nothing contained in this PLAN shall be construed as a contract of employment between the COMPANY or the ELIGIBLE EMPLOYEE, or as a right of the ELIGIBLE EMPLOYEE to be continued in the employ of the COMPANY, to remain as an officer of the COMPANY, or as a limitation on the right of the COMPANY to discharge any of its employees, with or without cause.

4.05 Benefits Unfunded and Unsecured . The benefits under this PLAN are unfunded, and the interest under this PLAN of any ELIGIBLE EMPLOYEE and such ELIGIBLE EMPLOYEE's right to receive a distribution of benefits under this PLAN shall be an unsecured claim against the general assets of the COMPANY.

4.06 Applicable Law . All questions pertaining to the construction, validity, and effect of the PLAN shall be determined in accordance with the laws of the United States, and to the extent not preempted by such laws, by the laws of the State of California.

4.07 Satisfaction of Claims . Notwithstanding Section 4.05 or any other provision of the PLAN, the COMPANY may at any time satisfy its obligations (either on a before-tax or after-tax basis) for any benefits accrued under the PLAN by the purchase from an insurance company of an annuity contract on behalf of an ELIGIBLE EMPLOYEE. Such purchase shall be in the sole discretion of the COMPANY and shall be subject to the ELIGIBLE EMPLOYEE'S acknowledgement that the COMPANY'S obligations to provide benefits hereunder have been discharged, without regard to the payments ultimately made under the contract. In the event of a purchase pursuant to this Section 4.07, the COMPANY may in its sole discretion make payments to or on behalf of an ELIGIBLE EMPLOYEE to defray the cost to such ELIGIBLE EMPLOYEE of any personal income tax in connection with the purchase.

EXHIBIT 10.25

2002 SHORT-TERM INCENTIVE PLAN

Background

At its meeting on February 20, 2002, the Nominating and Compensation Committee reviewed and approved the 2002 Short-Term Incentive Plan (STIP) for officers of PG&E Corporation and each subsidiary. The structure (Appendix A) establishes the weighting of corporate earnings per share (EPS), subsidiary EPS, and other performance factors for officers, including the credit ratings for PG&E National Energy Group, Inc. and its subsidiary, PG&E Energy Trading Holdings Corporation (Appendix B).

ATTACHMENT A

REVISED 2002 SHORT-TERM INCENTIVE PLAN STRUCTURE

Officer Group	Award Component	Weight	Performance Measures
PG&E Corporation	Corporate Financial Performance	50%	Corporate EPS from operations
	Credit Rating	50%	Credit rating of PG&E National Energy Group
President and CEO – Pacific Gas and Electric Company	Corporate Financial Performance	50%	Corporate EPS from operations
	Subsidiary Performance	50%	Respective subsidiary contribution to corporate EPS from operations
President and CEO – PG&E National Energy Group	Credit Rating	50%	Credit rating of PG&E National Energy Group
	Corporate Financial Performance	25%	Corporate EPS from operations
	Subsidiary Financial Performance	25%	Respective subsidiary contribution to corporate EPS from operations
Pacific Gas and Electric Company	Corporate Financial Performance	25%	Corporate EPS from operations
	Subsidiary Financial Performance	50–75%	Respective subsidiary contribution to corporate EPS from operations
	Subsidiary Operational Performance	0–25%	Financial, operating, and service measures determined by subsidiary CEO
PG&E National Energy Group	Credit Rating	50%	Credit rating of PG&E National Energy Group
	Corporate Financial Performance	25%	Corporate EPS from operations
	Subsidiary Financial Performance	0–25%	Respective subsidiary contribution to corporate EPS from operations
	Subsidiary Operational Performance	0–25%	Financial, operating, and service measures determined by subsidiary CEO

ATTACHMENT B

2002 STIP: CREDIT RATING PERFORMANCE MEASURE

Payout Level	Score	Performance Measure
Maximum	2.00	Increase in either credit rating agency's rating for PG&E National Energy Group or Energy Trading; the other credit ratings remain unchanged.
Above Target	1.75	Both agencies' credit ratings unchanged for PG&E National Energy Group and PG&E Energy Trading
Target	1.00	Both agencies' credit ratings at investment grade for PG&E National Energy Group and PG&E Energy Trading
Threshold	0.50	Both agencies' credit ratings at investment grade for PG&E National Energy Group or PG&E Energy Trading
No Payout	0.00	Both agencies' credit ratings at below investment grade for PG&E National Energy Group and PG&E Energy Trading

The agencies referred to above are Standard and Poor's and Moody's credit rating agencies.

EXHIBIT 11

PG&E CORPORATION
COMPUTATION OF EARNINGS PER COMMON SHARE

(in millions, except per share amounts)	Three Months Ended December 31, 2001	Three Months Ended December 31, 2000	Twelve Months Ended December 31, 2001	Twelve Months Ended December 31, 2000
BASIC EARNINGS PER SHARE (EPS) [1]				
Earnings available for common stock	$ 529	$ (4,117)	$ 1,099	$ (3,364)
Weighted average common shares outstanding [2]	363	363	363	362
Basic EPS	$ 1.46	$ (11.34)	$ 3.03	$ (9.29)
DILUTED EARNINGS PER SHARE (EPS) [1]				
Earnings available for common stock	$ 529	$ (4,117)	$ 1,099	$ (3,364)
Weighted average common shares outstanding	363	363	363	362
Add: outstanding options, reduced by the number of shares that could be repurchased with the proceeds from such exercise (at average market price)	3	—	1	—
Weighted average common shares outstanding as adjusted	366	363	364	362
Diluted EPS [3]	$ 1.45	$ (11.34)	$ 3.02	$ (9.29)

(1) This presentation is submitted in accordance with Item 601(b)(11) of Regulation S-K and Statement of Financial Accounting Standards No. 128.

(2) Weighted average common shares outstanding exclude shares held by a subsidiary of PG&E Corporation (23,815,500 shares at December 31, 2001 and 2000, respectively) and shares held by the Company in a trust to secure deferred compensation obligations (281,985 shares at December 31, 2001 and 2000, respectively).

(3) The diluted shares for the three months and year ended December 31, 2000 exclude 3 million and 2 million shares, respectively, due to the anti-dilution effects of the loss from continuing operations.

EXHIBIT 12.1

PACIFIC GAS AND ELECTRIC COMPANY
A DEBTOR-IN-POSSESSION
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Year ended December 31,

(dollars in millions)	2001	2000	1999	1998	1997
Earnings:					
Net income (loss)	$1,015	$(3,483)	$ 788	$ 729	$ 768
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	—	—	—	—	—
Income tax expense (benefit)	596	(2,154)	648	629	609
Net fixed charges	1,019	648	637	673	628
Total earnings	$2,630	$(4,989)	$2,073	$2,031	$2,005
Fixed charges:					
Interest on short-term borrowings and long-term debt, net	$ 981	$ 616	$ 604	$ 635	$ 586
Interest on capital leases	2	2	3	2	2
AFUDC debt	12	6	7	12	17
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	24	24	24	24	24
Total fixed charges	$1,019	$ 648	$ 638	$ 673	$ 629
Ratios of Earnings to Fixed Charges	2.58	(7.70) [1]	3.25	3.02	3.19

Note: For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, cash distributions from and equity in undistributed income or loss of Pacific Gas and Electric Company's less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "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 of subordinated debentures held by trust, interest on capital leases, and earnings required to cover the preferred stock dividend requirements.

(1) The ratio of earnings to fixed charges indicates a deficiency of less than one-to-one coverage aggregating $5,637 million.

EXHIBIT 12.2

PACIFIC GAS AND ELECTRIC COMPANY
A DEBTOR-IN-POSSESSION
COMPUTATION OF RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

	Year ended December 31,				
(dollars in millions)	2001	2000	1999	1998	1997
Earnings:					
Net income (loss)	$1,015	$(3,483)	$ 788	$ 729	$ 768
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	—	—	—	—	—
Income tax expense (benefit)	596	(2,154)	648	629	609
Net fixed charges	1,019	648	637	673	628
Total earnings	$2,630	$(4,989)	$2,073	$2,031	$2,005
Fixed charges:					
Interest on short-term borrowings and long-term debt, net	$ 981	$ 616	$ 604	$ 635	$ 586
Interest on capital leases	2	2	3	2	2
AFUDC debt	12	6	7	12	17
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	24	24	24	24	24
Total fixed charges	1,019	648	638	673	629
Preferred Stock Dividends:					
Tax deductible dividends	9	9	9	9	10

Pretax earnings required to cover non-tax deductible preferred stock dividend requirements	27	27	27	31	39
Total preferred stock dividends	36	36	36	40	49
Total combined Fixed Charges and Preferred Stock Dividends	$1,055	$ 684	$ 674	$ 713	$ 678
Ratio of Earnings to Combined Fixed and Preferred Stock Dividends	2.49	(7.29) [1]	3.08	2.85	2.96

Note: For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, cash distributions from and equity in undistributed income or loss of Pacific Gas and Electric Company's less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "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, interest of subordinated debentures held by trust, and earnings required to cover the preferred stock dividend requirements of majority owned subsidiaries. "Preferred stock dividends" represent pretax earnings which would be required to cover such dividend requirements.

(1) The ratio of earnings to combined fixed charges and preferred stock dividends indicates a deficiency of less than one-to-one coverage aggregating $5,673 million.

EXHIBIT 13

SELECTED FINANCIAL DATA

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

Long-term debt (excluding current portion)	3,019	3,342	4,877	5,444	6,218
Rate reduction bonds (excluding current portion)	1,450	1,740	2,031	2,321	2,611
Financial debt subject to compromise	5,651	—	—	—	—
Redeemable preferred stock and securities (excluding current portion)	586	586	586	586	694

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

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

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

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

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

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

•the outcome of the Utility's bankruptcy case, including:

– whether the Bankruptcy Court approves the amended disclosure statement relating to the Utility's proposed plan of reorganization (Plan) to be submitted to comply with the Bankruptcy Court's February 7, 2002 decision;

– whether the Bankruptcy Court confirms the Utility's Plan as amended to comply with the Bankruptcy Court's February 7, 2002 decision;

– whether the Bankruptcy Court confirms the alternative plan of reorganization to be submitted by the California Public Utilities Commission (CPUC) and the terms of such a plan;

– whether other parties submit alternative proposed plans of reorganization after the expiration of the period during which only the Utility may file a proposed plan;

– whether the CPUC takes action that would negatively affect the feasibility of the proposed Plan;

– whether the Plan is materially modified or amended;

– whether the Utility is required to re-assume the obligation to purchase power for its customers from the California Department of Water Resources (DWR) under circumstances that threaten to undermine the Utility's creditworthiness, financial condition, or results of operation;

– whether the Utility is required to accept assignment of the DWR's power purchase contracts;

• assuming the Bankruptcy Court confirms the proposed Plan, whether such confirmation can be challenged or appealed and the impact of any delay caused by such challenges or appeals on continued creditor support of the Plan and on continued feasibility of the Plan;

• whether, even if confirmed, the Plan becomes effective, which may be affected by, among other factors:

– risks relating to the issuance of new debt securities by each of the disaggregated entities, including higher interest rates than are assumed in the financial projections which could affect the amount of cash that could be raised to satisfy allowed claims, and the inability to successfully market the debt securities due to, among other reasons, an adverse change in market conditions or in the condition of the disaggregated entities before completion of the offerings;

– whether a favorable tax ruling or opinion is obtained regarding the tax-free nature of the transactions contemplated in the Plan;

– whether approval is obtained from the various federal regulatory agencies to implement the transactions contemplated in the Plan, the timing of that approval, and the timing and success of any appeals of such regulatory orders;

• assuming the Plan becomes effective, whether the Utility will be able to successfully disaggregate its businesses;

• the effect of the Utility's bankruptcy proceedings on PG&E Corporation and PG&E NEG, and in particular, the impact a protracted delay in the Utility's bankruptcy proceedings could have on PG&E Corporation's liquidity and access to capital markets;

• the outcome of the CPUC's pending investigation into whether the California investor-owned utilities, including the Utility, have complied with past CPUC decisions, rules, or orders authorizing their holding company formations, the outcomes of the lawsuits brought by the California Attorney General, the City and County of San Francisco, and the People of the State of California, against PG&E Corporation alleging unfair or fraudulent business acts or practices based on alleged violations of conditions established in the CPUC's holding company decisions, and the outcome of the California Attorney General's petition requesting revocation of PG&E Corporation's exemption from the Public Utility Holding Company Act of 1935, and the effect of such outcomes, if any, on PG&E Corporation, the Utility, and PG&E NEG;

•the extent to which the ability of PG&E Corporation to obtain financing or capital on reasonable terms is affected by the interpretation of the CPUC's holding company conditions, conditions in the general economy, the energy markets or capital markets;

•the outcome of the Utility's various regulatory proceedings pending at the CPUC, including the proceeding to determine future ratemaking for the Utility's retained generation (primarily hydroelectric assets and the Diablo Canyon Nuclear Power Plant), the 2002 attrition rate adjustment, and the 2003 General Rate Case;

•whether the CPUC's March 27, 2001 accounting decision regarding the Utility's under-collected wholesale power purchase costs is upheld and whether the Utility's lawsuit against the CPUC for recovery of those costs is successful;

•any changes in the amount of transition costs the Utility is allowed to collect from its customers, and the timing of the completion of the Utility's transition cost recovery;

•the amount and timing of regulatory valuation of the Utility's hydroelectric and other non-nuclear generation assets;

•the impact on earnings of the future operating performance at the Utility's Diablo Canyon Nuclear Power Plant (Diablo Canyon);

•legislative or regulatory changes affecting the electric and natural gas industries in the United States, including the pace and extent of efforts to restructure the electric and natural gas industries;

•the volatility of commodity fuel and electricity prices (which may result from a variety of factors, including: weather; the supply and demand for energy commodities; the availability of competitively priced alternative energy sources; the level of production and availability of natural gas, crude oil, and coal; transmission or transportation constraints; federal and state energy and environmental regulation and legislation; the degree of market liquidity; and natural disasters, wars, embargoes, and other catastrophic events); any resulting increases in the cost of producing power and decreases in prices of power sold, and whether the Utility's and PG&E NEG's strategies to manage and respond to such volatility are successful;

•PG&E NEG's ability to obtain financing from third parties, or from PG&E Corporation for its planned development projects and related equipment purchases and to refinance PG&E NEG's and its subsidiaries' existing indebtedness as it matures, in each case, on reasonable terms, while preserving PG&E NEG's credit quality; which could be negatively affected by conditions in the general economy, the energy markets, or the capital markets; and the extent to which the CPUC's holding company conditions may be interpreted to restrict PG&E Corporation's ability to provide financial support to PG&E NEG;

•the extent to which PG&E NEG's current or planned development of generation, pipeline, and storage facilities are completed and the pace and cost of that completion, including the extent to which commercial operations of these development projects are delayed or prevented because of various development and construction risks such as PG&E NEG's failure to obtain necessary permits or equipment, the failure of third-party contractors to perform their contractual obligations, or the failure of necessary equipment to perform as anticipated;

•the extent and timing of generating, pipeline, and storage capacity expansion and retirements by others;

•the performance of PG&E NEG's projects and the success of PG&E NEG's efforts to invest in and develop new opportunities;

•restrictions imposed upon PG&E Corporation and PG&E NEG under certain term loans of PG&E Corporation including maintenance of minimum segregated cash balances by PG&E Corporation and prohibitions on payment of dividends by both PG&E Corporation and PG&E NEG;

• future sales levels which, in the case of the Utility, will be affected by when the CPUC ultimately determines that direct access has been suspended and the level of exit fees that may be imposed on direct access customers; general economic and financial market conditions; and changes in interest rates;

• volatility resulting from mark-to-market accounting and the extent to which the assumptions underlying PG&E NEG's and the Utility's mark-to-market accounting and risk management programs are not realized;

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

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

- new accounting pronouncements; and

- the outcome of pending litigation.

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

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

2002 Guidance

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

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

Utility

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

In January 2001, the CPUC granted an interim rate increase of $0.010 per kWh. This increase, which could not be used to recover past procurement costs, was not sufficient to cover the on-going high wholesale electricity costs then being experienced. As a result of the higher energy prices and the insufficient rate increase, PG&E Corporation's and the Utility's credit ratings deteriorated to below investment grade. These credit downgrades, which occurred on January 16 and 17, 2001, were events of default under one of the Utility's revolving credit facilities and precluded PG&E Corporation's and the Utility's access to the capital markets. Accordingly, the banks

stopped funding under the Utility's revolving credit facility. On January 17, 2001, the Utility began to default on maturing commercial paper obligations. In addition, the Utility was no longer able to meet its obligations to generators, qualifying facilities (QFs), the Independent System Operator (ISO), and the Power Exchange (PX), and began making partial payments of amounts owed.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The Utility's 6,300 miles of transmission pipelines and three gas storage facilities would be transferred to GTrans, a California company. GTrans would hold the majority of the land, rights of way, and access rights currently associated with Utility gas transmission pipelines. GTrans would also assume certain continuing

contractual obligations currently held by the Utility's gas transmission operation. In addition, the Reorganized Utility would hold a 10- to 15-year transportation and gas storage contract with GTrans.

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

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

- Approve the Plan, authorizing the Utility to execute, implement, and take all actions necessary or appropriate to give effect to the transactions contemplated by the Plan and the Plan documents;

- Determine that the Utility, PG&E Corporation, and their affiliates are not liable or responsible for any DWR power contracts or purchases of power by the DWR, or any liabilities associated therewith;

- Prohibit the Reorganized Utility from accepting an assignment of the DWR contracts;

- Prohibit the Reorganized Utility from reassuming the net open position unless the Reorganized Utility is found to be creditworthy (as defined in the Plan documents) and a regulatory mechanism exists for the Reorganized Utility to recover its wholesale power purchases;

- Approve the execution of the proposed service and sales contracts between the Reorganized Utility and one or more of the disaggregated entities;

- Find that the CPUC affiliate transaction rules are not applicable to the restructuring transactions;

- Find that the approval of state and local agencies of California, including but not limited to the CPUC, shall not be required in connection with the restructuring transactions because the Bankruptcy Code preempts such state and local laws;

- Find that neither PG&E Corporation nor the Utility is required to comply with certain provisions of the California Corporations Code relating to corporate distributions and the sale of substantially all of a corporation's assets because the Bankruptcy Code preempts such state law;

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

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

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

- Prohibits the Utility from declaring or making cash distributions to PG&E Corporation (including by way of dividends and stock repurchases) through 2003;

- Provides for shareholders to contribute a projected $1.2 billion from the return on rate base for the period December 1, 2001, through January 3, 2003;

- Assumes the Utility will satisfy FERC's creditworthiness requirements and will resume purchasing the net open position no later than January 2003;

- Keeps current Utility rates in effect until no later than January 31, 2003, the assumed effective date of the CPUC plan. After all debts are paid in full, or reinstated, the CPUC would establish a cost of service rate structure;

- Establishes a Litigation Trust for the benefit of the Utility's customers which would be funded with (1) cash from the Utility in an amount to be determined, and (2) proceeds from settlement of various claims and causes of action including: (a) claims against PG&E Corporation (See Order Instituting Investigation (OII) into Holding Company Activities and Attorney General Complaint in Regulatory Matters), (b) refund claims from electric generators pending before FERC, if any, (c) other claims against electric generators, and (d) up to the first $1.75 billion of proceeds from the federal lawsuit filed by the Utility against the CPUC (See Federal Lawsuit in Regulatory Matters);

- Assumes all valid claims (together with post petition interest at the lowest non-default contract rate, or if no contract or non-default rate exists, then the federal judgment rate) will be satisfied in full through a combination of cash (estimated to be $6.9 billion by January 31, 2003), and reinstatement of certain of the Utility's long-term indebtedness and other obligations (approximately $5.8 billion); and

- Assumes the Utility will obtain a credit facility to fund capital expenditures, working capital, and if necessary, distributions to unsecured creditors.

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

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

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

PG&E Corporation

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

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

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

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

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

PG&E NEG

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

On December 2, 2001, a major participant in the energy business, Enron Corp. (Enron), filed for protection under Chapter 11 of the U.S. Bankruptcy Code (Enron Bankruptcy). The Enron Bankruptcy had little impact on the energy commodity markets which have remained liquid and efficient. Although Enron was a significant participant

in the energy trading business, a large portion of Enron's transactions was purely financial, thereby minimizing impacts on the physical energy markets. In addition, significant reporting in the public press during the months preceding the Enron Bankruptcy enabled many counterparties, including PG&E NEG, to reduce their exposure to Enron.

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

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

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

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

STATEMENTS OF CASH FLOWS FOR 2001, 2000, AND 1999

PG&E Corporation normally funds investing activities from cash provided by operations after capital requirements, and, to the extent necessary, external financing. PG&E Corporation's policy is to finance its investments with a capital structure that minimizes financing costs, maintains financial flexibility, and, with regard to the Utility, complies with regulatory guidelines. However, the Utility is currently operating as a debtor-in-possession under Chapter 11 of the Bankruptcy Code. While certain pre-petition debts are stayed, the Utility does not have access to external funding from the capital markets. Additionally, the Utility is in default

under its credit facilities, commercial paper, floating rate notes, senior notes, pollution control reimbursement agreements, and medium-term notes resulting from its failure to pay certain of its obligations. The event of default under each security has been stayed in accordance with the bankruptcy proceedings. The Utility has been making the capital investment in its infrastructure out of cash on hand under supervision of the Bankruptcy Court. It is uncertain whether the Utility will be able to continue to make such necessary capital investment in the future. See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the Chapter 11 bankruptcy filing.

PG&E Corporation – Consolidated

Cash Flows from Operating Activities

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

Cash Flows from Investing Activities

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

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

Cash Flows from Financing Activities

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

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

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

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

Utility

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

Cash Flows from Operating Activities

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

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

Cash Flows from Investing Activities

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

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

Cash Flows from Financing Activities

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

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

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

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

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

Net cash provided by financing activities in 2000 was $1,937 million, primarily due to net borrowings under the credit facilities and short-term borrowings of $2,630 million and five-year fixed-rate note issues of $680 million,

partially offset by the repayment of long-term debt of $597 million, common stock repurchased of $275 million, and dividends paid of $475 million.

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

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

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

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

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

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

PG&E NEG

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

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

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

Cash Flows from Operating Activities

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

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

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

Cash Flows from Investing Activities

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

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

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

Cash Flows from Financing Activities

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

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

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

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

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

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

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

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

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

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

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

COMMITMENTS AND CAPITAL EXPENDITURES

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

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

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

Utility

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

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

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

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

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

PG&E NEG

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

Construction Commitments

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

Turbine Purchase Commitments and Long-Term Service Agreements

To support its development program, PG&E NEG has contractual commitments and options for turbines and related equipment. Most significantly, PG&E NEG has secured contractual commitments and options for

combustion turbines and related equipment representing approximately 14,000 MW of net generating capacity, including 3,868 MW in greenfield development.

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

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

Greenfield Development

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

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

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

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

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

Equipment Procurement

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

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

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

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

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

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

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

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

The amounts set forth in the Commitments and Capital Expenditures Table above are based upon the current contractual provisions assuming all development projects under construction on the schedule set forth in such

contracts. These schedules remain subject to change and the commitments may be deferred or cancelled by contract terms.

Turbine Technology

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

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

Construction Issues

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

PG&E NEG Equity Commitment and Rating Triggers

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

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

- PG&E NEG's guarantee backing the $280 million equipment facility requires that PG&E NEG maintain a BBB- or Baa3 rating from either S&P or Moody's, respectively. In the event of a downgrade, PG&E NEG has 30 days to post an acceptable replacement security, or, following receipt of a payment demand from the lenders, PG&E NEG has 5 days to repay all outstanding borrowings under the facility.

- The $609 million equity commitments for Lake Road and La Paloma require that PG&E NEG maintain BBB- or Baa3 ratings from either S&P or Moody's. These rating triggers provide for a 30 day period to post replacement security after which lenders could request equity funding within five days.

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

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

Plains End – Financing and Equity Commitment

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

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

Tolling Agreements

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

Facility – Leases

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

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

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

Off-Balance Sheet – Non-Recourse Debt

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

Fuel Supply and Transportation Agreements

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

Power Purchase Agreements

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

Operating Leases

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

Other Commitments

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

Guarantees Supporting Trading Related Agreements

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

In addition to guarantee supporting tolling agreements, as of December 31, 2001, PG&E NEG and its subsidiaries provided $2.3 billion of guarantees to counterparties in support of its energy trading operations. This includes provision of fuel and pipeline capacity to, and sale of energy products from its power plants. These guarantees were provided in favor of approximately 200 counterparties to permit and facilitate physical and financial transactions in gas, pipeline capacity, power, coal, and related commodities and services with these entities. Typically, the overall exposure under these guarantees is only a fraction of the face value of the guarantees, since not all counterparty credit limits are fully utilized at any time and there may be no outstanding transactions or financial exposure underlying an outstanding guarantee. PG&E NEG receives similar deposits,

letters of credit, and guarantees as collateral for credit extended by PG&E NEG to these, in many cases, same counterparties. These offsetting exposures can often be netted in lieu of posting alternative collateral. As of December 31, 2001, PG&E NEG's net exposure under its guarantees was approximately 8 percent or about $190 million. This exposure is a contingent obligation that could be called only if PG&E NEG or one of its subsidiaries fails to meet and cure a payment obligation.

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

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

Guarantees Supporting Other Agreements with Third Parties

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

PG&E GTN Pipeline Expansion

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

North Baja Pipeline

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

PG&E Corporation Guarantees

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

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

RESULTS OF OPERATIONS

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

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

(1) All inter-segment transactions are eliminated.

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

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

PG&E Corporation – Consolidated

Overall Results

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

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

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

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

- The Utility's generation-related component of its electric revenues was greater than its generation-related costs by $458 million for the year ended December 31, 2001, and was caused primarily by the following three factors. First, the Utility recognized an offset against previously expensed purchased power costs of $327 million related to the market value of terminated bilateral contracts. Second, beginning in June 2001, the Utility began collecting revenues associated with the CPUC's March 27, 2001, interim energy procurement surcharges. Third, in the second quarter and continuing throughout the balance of the year, the wholesale energy market stabilized and the DWR began providing for the entire net open position.

- As a result of the liquidity crisis attributable to the California energy crisis, PG&E Corporation has had a significant increase in unpaid debts and has increased its borrowings significantly, all accruing interest. Additionally, the effective interest rate due on these new borrowings has increased because of the higher risk associated with PG&E Corporation's financial position. The incremental cost of these borrowings was $262 million, after tax, for the year ended December 31, 2001, of which $218 million relates to the Utility and $44 million was incurred by PG&E Corporation.

- The Utility has incurred incremental financial and legal expenses associated with the bankruptcy proceedings and the development of a plan of reorganization. For the year ended December 31, 2001, total incremental expenses were approximately $78 million, after tax, consisting of $42 million of costs relating to the Utility and $36 million of costs pertaining to PG&E Corporation.

- During 2001, the Utility recognized losses of approximately $66 million, after tax, associated with the involuntary termination of gas transportation hedges caused by a decline in the Utility's credit rating.

- During the third quarter of 2001, the CPUC issued two decisions modifying its previous decision in the Utility's 1999 General Rate Case (GRC). The first, to correct a tax computational error in the CPUC's decision, had the impact of adding approximately $34 million to net income (approximately $25 million related to 1999 and 2000), and the second modification had the impact of decreasing net income by approximately $70 million of which $51 million related to 1999 and 2000.

- PG&E NEG increased earnings by $31 million for the year ended December 31, 2001, as compared to 2000. This increase was the result of higher gross margins at the wholesale energy business, the gain on a sale of a development project, and a lower effective federal tax rate resulting from synthetic fuel credits. In addition, the 2000 results include a $40 million loss on discontinued operations.

- PG&E NEG took a charge against income in the fourth quarter of 2001 for the net exposure of $35 million relating to trading contracts with Enron. For a detailed discussion of this write-off, please see Note 4 of the Notes to the Consolidated Financial Statements.

• For various transactions that were recorded in 2000, such as the Utility's write-off of its remaining generation-related regulatory assets and under-collected purchased power costs, and the Utility's provision for potential losses associated with litigation, there were no similar transactions in 2001. As such, performance in 2001, when compared to the prior year, is impacted by those transactions that occurred in 2000. The 2000 transactions are discussed further below.

• The effective tax rate for PG&E Corporation decreased to 35.8 percent in 2001, as compared to 37.9 percent in 2000, principally as a result of synthetic-fuel credits earned during the year.

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

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

• The Utility's earnings were impacted as a result of the write-off of its remaining generation-related regulatory assets and under-collected purchased power costs ($4.1 billion, after tax). Because of the substantial uncertainty created by the California energy crisis, the Utility could no longer conclude that energy and transition costs, which had been deferred on its Consolidated Balance Sheets, were probable of recovery. Under Statement of Financial Accounting Standard (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," if a rate mechanism provided by legislation or other regulatory authority were subsequently established that made recovery from regulated rates probable as to all or a portion of the under-collection that was previously charged against earnings, a regulatory asset would be reinstated with a corresponding increase in earnings.

• As a result of the high cost of power, with no offsetting revenues, the Utility and PG&E Corporation had a net loss for California tax purposes. California law does not permit carrybacks of such losses and only permits carryforwards of 55 percent of such losses. As a result, PG&E Corporation was unable to recognize $79 million of state tax benefits because of California law. Income tax expense was also higher due to tax depreciation adjustments and a reduction in investment tax credits.

• In 2000, the Utility recorded a provision ($83 million, after tax) for potential losses associated with litigation discussed in Note 16 of the Notes to the Consolidated Financial Statements.

• At the end of 1999, PG&E Corporation announced its plans to dispose of PG&E GTT and these assets were written down to estimated fair value, resulting in a charge of $890 million ($2.24 per share). PG&E GTT operated at a breakeven basis in 2000, while it reported a net loss from operations of $7 million ($0.02 per share) in 1999. These operations were sold on December 22, 2000.

• Also at the end of 1999, PG&E Corporation announced its plans to dispose of PG&E ES and these assets were written down to net realizable value. PG&E ES operated at a loss during 2000. However, those losses were charged against reserves established in 1999 and did not impact the current results from operations, while PG&E ES reported losses of $98 million ($0.27 per share) for 1999. Additionally, during the latter half of 2000, PG&E Corporation recorded after-tax charges of $40 million ($0.11 per share) to reflect the closing of transactions to dispose of the retail energy services business and related commodity portfolio.

• PG&E ET's net income in 2000, net of restructuring charges of $13 million, after tax ($0.04 per share), related to the move of natural gas trading operations from Houston, Texas, to Bethesda, Maryland, increased $57 million compared to 1999 results due to across-the-board improvements in natural gas and power trading, asset management, and structured transactions. While trading in electric commodities has generally been profitable, the results of the gas trading operations have improved significantly as a result of structured transactions. Additionally, the gas trading operations benefited from the highest gas prices in a number of years. The power trading operations have benefited from volatile prices throughout the United States.

• PG&E Gen and PG&E GTN earnings decreased slightly from 1999 levels, primarily attributable to a decline in operating results in the generating business and a decrease in operating income at PG&E GTN primarily as a result of settlements received in the amount of $19 million for negotiations regarding transportation contracts and other related issues, resulting in the restructuring and/or termination of these transportation contracts in 1999 with no similar transactions in 2000.

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

Dividends

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

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

Utility

Overall Results

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

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

Electric Operations

Electric Revenues

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

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

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

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

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

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

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

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

Cost of Electric Energy

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

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

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

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

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

Gas Operations

Gas Revenues

In 2001, gas revenues increased $353 million due to a higher average price of gas, which was passed on to customers and collected in gas revenues. The increase was offset by an approximate 4 percent decrease in usage

in 2001 primarily as a result of conservation efforts. The average bundled price of gas sold in 2001 was $10.55 per Mcf compared to $8.40 per Mcf in 2000.

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

Cost of Gas

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

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

Other Operating Expenses

Operating and Maintenance

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

Depreciation, Amortization, and Decommissioning

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

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

Interest Expense

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

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

Reorganization Fees and Expenses

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

Dividends

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

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

PG&E NEG

Operating Income

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

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

Operating Revenues

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

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

Operating Expenses

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

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

Dividends

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

REGULATORY MATTERS

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

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

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

1999 General Rate Case

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

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

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

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

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

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

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

2001 Attrition Rate Adjustment Request

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

2003 GRC and 2002 ARA Request

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

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

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

Retained Generation Ratemaking Proceeding

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

Further, the Utility believes that the ratemaking for the Utility's Diablo Canyon facility should be based on the specific "benefits sharing" formula established in a 1997 CPUC decision. Under the formula, the Utility would share with ratepayers 50 percent of the net operating benefits or costs of operating Diablo Canyon after the rate freeze. The Incremental Cost Incentive Price (ICIP) ratemaking for Diablo Canyon used to recover the Diablo Canyon facility's operating costs and the cost of capital additions incurred after December 31, 1996 was originally scheduled to end December 31, 2001.

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

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

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

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

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

Revenue Adjustment Proceeding

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

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

Annual Transition Cost Proceeding

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

In September 2000, the Utility filed its 2000 ATCP application seeking approval of amounts recorded in the TCBA and generation memorandum accounts for the period July 1, 1999, through June 30, 2000. The CPUC has

not yet issued a decision covering that period. In September 2001, the Utility filed its 2001 ATCP application seeking approval of the recorded amounts for the period July 1, 2000, through June 30, 2001.

ISO Tariff Creditworthiness Requirements

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

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

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

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

FERC Prospective Price Mitigation Relief

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

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

1. Its extension to all hours of the day,

2. The reaffirmation of its requirement that all generators in California offer available generation for sale to the ISO's real-time energy market,

3. The establishment of a single market clearing price in the ISO's spot markets during emergency hours, and

4. The establishment of a maximum market clearing price for spot market sales in all hours.

In June and July 2001, the FERC's chief ALJ conducted settlement negotiations among power generators, the State of California, and the California investor-owned utilities, in an attempt to resolve disputes regarding past power sales. The State represented that it and the California investor-owned utilities are owed $8.9 billion for electricity overcharges by the generators. The negotiations did not result in a settlement, but the judge recommended that the FERC conduct further hearings to determine what the power sellers and buyers are each owed. The Utility does not believe these matters will be resolved until mid- to late 2002, nor can it predict

whether a refund will be ordered or the amount the Utility might receive. In connection with this proceeding, on August 17, 2001, the ISO submitted data indicating that a PG&E NEG affiliate, PG&E Energy Trading- Power, L.P. (ET Power) may be required to refund approximately $26 million. However, the FERC has indicated that unpaid amounts owed by the ISO and the PX may be used as offsets to any refund obligations. Potential offsets would significantly reduce any potential refund required to be made by ET Power. Finalization of any refunds and offsets are subject to the on-going FERC proceeding.

Direct Access Service

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

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

Cost of Capital Proceedings

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

FERC Transmission Rate Cases

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

In July 2001, the FERC approved a settlement that permits the Utility to collect $262 million annually, (net of the 2002 Transmission Revenue Balancing Account) in electric transmission rates beginning on May 6, 2001. This decrease in transmission rates relative to previous time periods is due to unusually large balances paid to the Utility by the ISO for congestion management charges and other transmission-related services billed by the ISO

that are booked in the Transmission Revenue Balancing Account. These balances paid by the ISO are offset against the Utility's transmission revenue requirement. The Utility does not expect the outcome of these settlements to have a material adverse effect on its results of operations or financial condition.

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

Scheduling Coordinator Costs

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

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

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

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

Gas Accord II Application

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

Under the Utility's proposal, those provisions of the Gas Accord currently scheduled to expire on January 1, 2003, will be extended through December 31, 2004, while certain storage-related provisions scheduled to expire on April 1, 2003, will be extended through March 31, 2005. No change is proposed to the previously approved rates in effect as of December 2002 or, in the case of certain storage provisions, as of March 31, 2003. The Utility believes the two-year extension that has been proposed will allow for resolution of many uncertainties affecting

gas markets today, including the Utility's proposed plan of reorganization. The CPUC has not issued a decision in this proceeding. The Utility cannot predict what the outcome of the decision will be, or whether the outcome will have a material adverse effect on its results of operations or financial condition.

Federal Lawsuit

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

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

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

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

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

In a related decision, the CPUC denied the motions filed by the California utility holding companies to dismiss the holding companies from the pending investigation on the basis that the CPUC lacks jurisdiction over the holding companies. However, in the decision interpreting the first priority condition discussed above, the CPUC separately dismissed PG&E Corporation (but no other utility holding company) as a respondent to the proceeding. In its written decision mailed on January 11, 2002, the CPUC stated that PG&E Corporation was being dismissed so

that an appropriate legal forum could decide expeditiously whether adoption of the Utility's proposed plan of reorganization would violate the first priority condition.

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

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

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

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

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

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

State of California Senate Bill X2

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

Annual Earnings Assessment Proceeding (AEAP)

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

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

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

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

ENVIRONMENTAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established to both maintain and improve the quality of the environment. Where PG&E Corporation's and the Utility's properties contain hazardous substances, these laws and regulations require PG&E Corporation and the Utility to remove those substances or remedy effects on the environment. See Note 16 of the Notes to the Consolidated Financial Statements for further discussion of environmental matters.

Utility

The Utility may be required to pay for environmental remediation at sites where it has been or may be a potentially responsible party under the Comprehensive Environmental Response, Compensation, and Liability Act, and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances, even if it did not deposit those substances on the site.

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

Hazardous Waste Remediation

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

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

- Up to $22 million in each calendar year in which the Chapter 11 case is pending to continue its hazardous substance remediation programs and procedures, and

- Any additional amounts necessary in emergency situations involving post-petition releases or threatened releases of hazardous substances, subject to the Bankruptcy Court's specific approval.

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

Environmental Claims

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

Moss Landing

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

Diablo Canyon

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

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

PG&E NEG

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

In May 2000, PG&E NEG received an Information Request from the U.S. Environmental Protection Agency (EPA), pursuant to Section 114 of the Federal Clean Air Act (CAA). The Information Request asked PG&E NEG to provide certain information relative to the compliance of the Brayton Point and Salem Harbor Generating Stations with the CAA. No enforcement action has been brought by the EPA to date. PG&E NEG has had very preliminary discussions with the EPA to explore a potential settlement of this matter. As a result of this and related regulatory initiatives by the Commonwealth of Massachusetts, PG&E NEG is exploring initiatives that would assist it to achieve significant reductions of sulfur dioxide, nitrogen oxide, and thermal emissions by 2006. PG&E NEG believes that it would meet these requirements through installation of controls at the Brayton Point and Salem

Harbor plants and estimates that capital expenditures on these environmental projects will be approximately $266 million over the next five years. PG&E NEG believes that it is not possible to predict at this point whether any such settlement will occur or, in the absence of a settlement, the likelihood of whether the EPA will bring an enforcement action.

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

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

Inflation

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

Quantitative and Qualitative Disclosures About Market Risk

Risk Management Activities

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

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

PG&E Corporation applies mark-to-market accounting to all of its trading activities, under the guidance in Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involving Energy Trading and Risk Management Activities," which are recorded at fair value with realized and unrealized gains (losses) in earnings. The recognized but unrealized balances are recorded on the Consolidated Balance Sheets as price risk management assets and liabilities. Non-trading contracts that meet the definition of a derivative under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," may be classified as normal purchases and sales or cash flow hedges. Those derivatives that qualify for normal purchases and sales treatment are exempt

from the fair value requirements of SFAS No. 133. Derivatives that are designated and qualify for cash flow hedge treatment are tested for their effectiveness in hedging the underlying position. Gains or losses associated with the hedge effectiveness are recorded on the Consolidated Balance Sheets in Other Comprehensive Income (OCI) and are reclassified into earnings in the period in which the underlying transaction affects earnings. Gains and losses associated with the ineffective portion of such hedges are recognized in earnings immediately. PG&E Corporation, through PG&E NEG, participates in trading and non-trading activities; the Utility participates only in non-trading activities.

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

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

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

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

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

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

Market Risk

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

Commodity Price Risk

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

Utility Electric Commodity Price Risk

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

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

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

Utility Natural Gas Commodity Price Risk

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

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

PG&E NEG Commodity Price Risk

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

Value-at-Risk

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

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

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

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

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

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

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

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

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates could adversely affect earnings and cash flows. Specific interest rate risks for PG&E Corporation and the Utility include the risk of increasing interest rates on short-term and long-term floating rate debt, the risk of decreasing rates on floating rate assets which have been financed with fixed rate debt, the risk of increasing interest rates for planned new fixed long-term financings, and

the risk of increasing interest rates for planned refinancing using long-term fixed rate debt. In addition, the Utility is exposed to changes in interest rates on interest accruing on loan payments and trade payables currently in default.

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

Foreign Currency Risk

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

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

Credit Risk

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

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

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

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

The majority of counterparties to which PG&E Corporation and the Utility are exposed are considered to be of investment grade, determined using publicly available information including an S&P's rating of at least BBB-.

$296 million or 25 percent of PG&E Corporation's gross credit exposure and $59 million or 22 percent of the Utility's gross credit exposure is below investment grade. PG&E Corporation has regional concentrations of credit exposure to counterparties that primarily conduct business throughout the western United States (30 percent) and also to counterparties that primarily conduct business throughout the entire United States (51 percent). The Utility has a regional concentration of credit exposure to counterparties that primarily conduct business throughout the entire United States (93 percent).

Related Party Agreements

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

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

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

Additional Security Measures

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

Critical Accounting Policies

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

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

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

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

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

New Accounting Standards

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

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

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

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

earnings. The cumulative effect of this change in accounting principle increased earnings by approximately $9 million (after-tax).

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

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

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

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

Legal Matters

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

PG&E Corporation

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

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

Net Earnings (Loss) Per Common Share, Basic	$ 3.03	$ (9.29)	$ (0.20)
Income (Loss) Per Common Share, from Continuing Operations, Diluted	$ 2.99	$ (9.18)	$ 0.04
Net Earnings (Loss) Per Common Share, Diluted	$ 3.02	$ (9.29)	$ (0.20)
Dividends Declared Per Common Share	$ —	$ 1.20	$ 1.20

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

PG&E Corporation

CONSOLIDATED BALANCE SHEETS
(in millions)

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

PG&E Corporation

CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

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

Accumulated other comprehensive income (loss)	30	(4)
Total common stockholders' equity	4,322	3,172
Commitments and Contingencies (Notes 1, 2, 3, 15, and 16)	—	—
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 35,862	$ 36,152

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

PG&E Corporation

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

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

Cash and cash equivalents at December 31	$ 5,421	$ 2,430	$ 340
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 579	$ 748	$ 729
Income taxes paid (refunded), net	(692)	20	723
Supplemental disclosures of noncash investing and financing activities			
Retirement of long-term debt on the sale of PG&E Gas Transmission, Texas	—	564	—
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities	11,206	—	—

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

PG&E Corporation

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

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

Common stock issued (739,158 shares)	16	—	—	—	16
Common stock repurchased (34,037 shares)	(1)	—	—	—	(1)
Other	—	—	2	—	2
Balance at December 31, 2001	$ 5,986	$ (690)	$ (1,004)	$ 30	$ 4,322

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

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

CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions)

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

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

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

CONSOLIDATED BALANCE SHEETS
(in millions)

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

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

CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

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

Additional paid-in capital	1,964	1,964
Accumulated deficit	(989)	(1,979)
Accumulated other comprehensive loss	(2)	—
Total stockholders' equity	2,398	1,410
Commitments and Contingencies (Notes 1, 2, 3, 15, and 16)	—	—
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 25,137	$ 21,988

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

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

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

Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	$ 87	$ —	$ —
Cash paid for:			
Interest (net of amounts capitalized)	361	587	531
Income taxes paid (refunded), net	(556)	—	1,001
Reorganization professional fees and expenses	19	—	—
Supplemental disclosures of noncash investing and financing activities			
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities	11,384	—	—

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

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

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

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

Comprehensive income								$ 1,013
Preferred stock dividend requirement	—	—	—	(25)	—	(25)	—	
Balance at December 31, 2001	$ 1,606	$ 1,964	$ (475)	$ (989)	$ (2)	$ 2,104	$ 294	

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1: General

Basis of Presentation

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

This is a combined annual report of PG&E Corporation and the Utility. Therefore, the Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's consolidated financial statements include the accounts of PG&E Corporation, the Utility, and PG&E Corporation's wholly owned and controlled subsidiaries. The Utility's consolidated financial statements include its accounts as well as those of its wholly owned and controlled subsidiaries. All significant inter-company transactions have been eliminated from the consolidated financial statements.

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

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

Operations

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

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

Cash and Cash Equivalents

Cash and cash equivalents include cash and working funds with original maturities of three months or less when purchased. Cash equivalents are stated at cost, which approximates fair value. PG&E Corporation's and the Utility's cash equivalents are held in a variety of funds that primarily invest in certificates of deposit, time deposits,

bankers' acceptances, and other short-term securities issued by banks, asset-backed securities, repurchase agreements, high-grade commercial paper, and discounted notes issued or guaranteed by the United States government or its agencies. In general, the securities are purchased on the date of issue and held in the accounts until maturity. Substantially all of PG&E Corporation's and the Utility's cash equivalents on hand at December 31, 2001, have matured and been reinvested. At December 31, 2001, three funds held balances greater than 10 percent of PG&E Corporation's and the Utility's cash and cash equivalents balance. They were: the Citifunds Institutional Liquid Reserves Fund, the Dreyfus Cash Management Plus Fund, and the Fiduciary Trust Company International.

Restricted Cash

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

Inventories

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

Income Taxes

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

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

Earnings (Loss) Per Share

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

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

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

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

Property, Plant and Equipment

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

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

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

depreciation rates were 3.63 percent, 4.54 percent, and 3.41 percent for the years ended December 31, 2001, 2000, and 1999, respectively. Estimated useful lives of property, plant and equipment are as follows:

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

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

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

Investment in Unconsolidated Affiliates

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

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

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

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

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

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

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

Capitalized Software Costs

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

Gains and Losses on Reacquired Debt

Gains and losses on reacquired debt associated with regulated operations that are subject to the provisions of SFAS No. 71 are deferred and amortized over the remaining original amortization period of the debt reacquired, consistent with ratemaking principles. Gains and losses on reacquired debt associated with unregulated operations are recognized in earnings as extraordinary gains or losses at the time such debt is reacquired.

Intangible Assets and Asset Impairment

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

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

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

Regulation and Statement of Financial Accounting Standards No. 71

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 applies to regulated entities whose rates are designed to recover the costs of providing service. The Utility is regulated by the CPUC, the FERC, and the Nuclear Regulatory Commission (NRC), among others. The gas transmission business in the Pacific Northwest is also regulated by the FERC.

SFAS No. 71 provides for the recording of regulatory assets and liabilities when certain conditions are met. Regulatory assets represent the capitalization of incurred costs that would otherwise be charged to expense when

it is probable that the incurred costs will be included for ratemaking purposes in the future. Regulatory liabilities represent rate actions of a regulator that will result in amounts that are to be credited to customers through the ratemaking process.

Regulatory assets comprise the following:

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

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

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

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

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

Regulatory Balancing Accounts

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

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

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

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

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

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

Revenue Recognition

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

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

Accounting for Price Risk Management Activities

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

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

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

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

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

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

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

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

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

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

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) reports a measure for accumulated changes in equity of an enterprise that result from transactions and other economic events other than transactions with shareholders. PG&E Corporation's and the Utility's accumulated other comprehensive income (loss) consists principally of changes in the market value of certain cash flow hedges with the implementation of SFAS No. 133 on January 1, 2001, as well as foreign currency translation adjustments.

Accounting for Major Maintenance

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

Related Party Agreements

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

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

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

Stock-Based Compensation

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

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

Reclassifications

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1. The Reorganized Utility establishes an investment grade credit rating and receives assurances that its credit rating will not be downgraded as a result of the reassumption of the obligation to meet the net open position;

2. There is an objective retail rate recovery mechanism in place pursuant to which the Reorganized Utility is able to fully recover in a timely manner its wholesale costs of purchasing electricity to meet the net open position;

3. There are objective standards in place regarding pre-approval of procurement transactions; and

4. After reassumption of the obligation to meet the net open position, the conditions in clauses (2) and (3) remain in effect.

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

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

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

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

1. Approve the Plan documents, authorizing the Utility to execute, implement and take all actions necessary or appropriate to give effect to the transactions contemplated by the Plan and the Plan documents;

2. Determine that the Utility, PG&E Corporation and their affiliates are not liable or responsible for any DWR power contracts or purchases of power by the DWR, and any liabilities associated therewith;

3. Prohibit the Reorganized Utility from accepting an assignment of the DWR contracts;

4. Prohibit the Reorganized Utility from reassuming the net open position unless the Reorganized Utility is found to be creditworthy (as defined in the Plan documents) and a regulatory mechanism exists for the Reorganized Utility to recover its wholesale power purchases;

5. Approve the execution of the proposed service and sales contracts between the Reorganized Utility and one or more of the disaggregated entities;

6. Find that the CPUC affiliate transaction rules are not applicable to the restructuring transactions;

7. Find that the approval of state and local agencies of California, including but not limited to, the CPUC, shall not be required in connection with the restructuring transactions because the Bankruptcy Code preempts such state and local laws;

8. Find that neither PG&E Corporation nor the Utility is required to comply with certain provisions of the California Corporations Code relating to corporate distributions and the sale of substantially all of a corporation's assets because the Bankruptcy Code preempts such state law; and

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

1. The confirmation order, in form and substance acceptable to PG&E Corporation and the Utility, shall have been signed by the Bankruptcy Court on or before June 30, 2002, and shall have become a final order;

2. The Effective Date shall have occurred on or before January 1, 2003;

3. All actions, documents and agreements necessary to implement the Plan shall have been effected or executed;

4. PG&E Corporation and the Utility shall have received all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions or documents that are determined by PG&E Corporation and the Utility to be necessary to implement the Plan;

5. Standard & Poors (S&P) and Moody's Investors Service (Moody's) shall have established credit ratings for each of the securities to be issued by the Reorganized Utility, ETrans, GTrans, and Gen of not less than BBB- and Baa3, respectively;

6. The Plan shall not have been modified in a material way since the confirmation date; and

7. The registration statements pursuant to which the new securities will be issued shall have been declared effective by the SEC, the Reorganized Utility shall have consummated the sale of its new securities to be sold under the Plan, and the new securities of each of ETrans, GTrans, and Gen shall have been priced and the trade date with respect to each shall have occurred.

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

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

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

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

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

• Prohibits the Utility from declaring or making cash distributions to PG&E Corporation (including by way of dividends and stock repurchases) through 2003;

• Provides for shareholders to contribute a projected $1.2 billion from the return on rate base for the period December 1, 2001, through January 3, 2003;

• Assumes the Utility will satisfy FERC's creditworthiness requirements and will resume purchasing the net open position no later than January 2003;

• Keeps current Utility rates in effect until no later than January 31, 2003, the assumed effective date of the CPUC plan. After all debts are paid in full, or reinstated, the CPUC would establish a cost of service rate structure;

• Establishes a Litigation Trust for the benefit of the Utility's customers which would be funded with (1) cash in an amount to be determined from the Utility, and (2) proceeds from settlement of various claims and causes of action including: (a) claims against PG&E Corporation (See Order Instituting Investigation (OII) into Holding Company Activities and Attorney General Complaint in Regulatory Matters), (b) refund claims from electric generators pending before FERC, if any, (c) other claims against electric generators, and (d) up to the first $1.75 billion of proceeds from the federal lawsuit filed by the Utility against the CPUC (See Federal Lawsuit in Regulatory Matters);

• Assumes all valid claims (together with post petition interest at the lowest non-default contract rate, or if no contract or non-default rate exists, then the federal judgment rate) will be satisfied in full through a combination of cash (estimated to be $6.9 billion by January 31, 2003), and reinstatement of certain of the Utility's long-term indebtedness and other obligations (approximately $5.8 billion); and

• Assumes the Utility will obtain a credit facility to fund capital expenditures, working capital, and if necessary, distributions to unsecured creditors.

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

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

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

Note 3: California Electric Industry Restructuring

In 1998, California implemented electric industry restructuring and established a market framework for electric generation in which generators and other power providers were permitted to charge market-based prices for wholesale power. The restructuring of the electric industry was mandated by the California Legislature in Assembly Bill (AB) 1890. The electric industry restructuring law mandated a rate freeze and included a plan for recovery of generation-related costs that were expected to be uneconomic under the new market framework (transition costs). Additionally, the CPUC strongly encouraged the Utility to divest greater than 50 percent of its fossil generation facilities and discouraged the Utility from continuing to operate remaining generation facilities by reducing the

allowed return on such assets. The new market framework called for the creation of the Power Exchange (PX) and the Independent System Operator (ISO). Before it ceased operating in March 2001, the PX established market-clearing prices for electricity. The ISO's role was to schedule delivery of electricity for all market participants and operate certain markets for electricity. Until December 15, 2000, the Utility was required to sell all of its owned and contracted generation to, and purchase all electricity for its retail customers from, the PX. Customers were given the choice of continuing to buy electricity from the Utility or buying electricity from independent power generators or retail electricity suppliers. Most of the Utility's customers continued to buy electricity through the Utility.

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

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

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

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

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

Further affecting the recovery of transition costs and the end of the rate freeze, in March 2001, the CPUC adopted an accounting proposal introduced by TURN. This proposal required the transfer on a monthly basis of the balance in the Utility's Transition Revenue Account (TRA), whether under-

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

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

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

Generation Divestiture

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

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

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

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

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

The Utility's Retained Generation Ratemaking Proceeding

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

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

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

California Department of Water Resources Purchases

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

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

On March 27, 2001, the CPUC issued a decision ordering the Utility and the other California investor-owned utilities to pay the DWR a per-kWh price for the power purchased by the DWR for the Utility's customers. The CPUC determined that the company-wide average generation-related rate was approximately $0.095 per kWh (including the January 2001 $0.010 per kWh and the March 2001 average $0.030 per kWh increases). The Utility, acting as an agent for the DWR with respect to the collection of the portion of the Utility's retail rates that must be paid to the DWR, does not include these amounts (pass-through revenues) in its Consolidated Statements of Operations (see further discussion below). Total pass-through revenues recorded by the Utility for the year ended December 31, 2001, were $2,173 million.

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

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

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

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

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

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

ISO Purchases

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

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

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

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

Subsequently, the ISO has issued invoices to the DWR for the amounts in dispute. The DWR is in the process of paying substantially all

such invoices for the period from January 17, 2001, forward. On December 7, 2001, the DWR filed an application for rehearing of the FERC November 7, 2001, order, alleging, among other things, that the FERC order was illegal and unconstitutional because it restricted the DWR's unilateral discretion to determine

the prices it would pay for the third party power under the ISO invoices. If the FERC upholds its previous ruling that the DWR, not the Utility, is responsible for amounts billed by the ISO to the DWR for the period from January 17, 2001, through April 6, 2001, the Utility will reverse the $1 billion accrued during 2001. However, if the Utility reverses the ISO accrual, it would need to record an accrual for its obligation to the DWR for such energy purchases. The Utility expects that this DWR accrual would not exceed the ISO reversal. See above discussion in California Department of Water Resources Purchases.

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

Statutory End of the Transition Period

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

Cost of Electric Energy

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

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

Note 4: Price Risk Management

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

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

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

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

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

Interest Rate Swaps

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

Credit Risk

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

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

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

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

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

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

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

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

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

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

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

Note 5: Fair Value of Financial Instruments

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

• The fair values of cash and cash equivalents, restricted cash and deposits, net accounts receivable, short-term borrowings, current portion of long-term debt, current portion of Rate Reduction Bonds, and accounts payable, approximate their carrying values as of December 31, 2001, and 2000.

• The fair values of long-term receivables and liabilities are estimated using discounted cash flows analysis, based on PG&E Corporation's current incremental borrowing rate. The fair value of most of the Utility's debt is determined using quoted market prices, but the fair value of a small portion of the Utility's debt is determined using the present value of future cash flows.

• The fair values of nuclear decommissioning funds, Rate Reduction Bonds, the Utility preferred stock with mandatory redemption provisions, and utility obligated mandatorily redeemable preferred securities of trust holding solely Utility subordinated debentures are determined based on quoted market prices.

• The fair values of interest rate swap agreements are estimated by calculating the present value of the difference between the total fixed payments of the interest rate swap agreements and the total floating payments using the appropriate current market interest rates. Before PG&E Corporation adopted SFAS No. 133 on January 1, 2001, interest rate swaps were not carried on the balance sheet. The fair value of interest rate swaps at December 31, 2000, was a $74 million liability. Beginning January 1, 2001, PG&E Corporation has accounted for its interest rate swaps as derivatives under SFAS No. 133. These contracts are carried at fair value as a component of price risk management assets and liabilities on the accompanying Consolidated Balance Sheets at December 31, 2001.

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

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

Note 6: Acquisitions and Disposals

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

estimated. The PG&E ES business segment generated net losses from operations of $40 million (or $0.11 per share) for the year ended December 31, 1999.

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

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

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

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

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

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

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

Note 7: Common Stock

PG&E Corporation

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

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

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

Utility

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

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

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

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

Shareholder Rights Plan of PG&E Corporation

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

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

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

The Rights also have certain anti-takeover effects and will cause substantial dilution to a person or group that attempts to acquire PG&E Corporation on terms not approved by PG&E Corporation's Board of Directors, unless the offer is conditioned on a substantial number of Rights being acquired. The Rights should not interfere with any approved merger or other business combination, as the Board of Directors, at its option, may redeem the Rights.

Thus, the Rights are intended to encourage persons who may seek to acquire control of PG&E Corporation to initiate such an acquisition through negotiations with PG&E Corporation's Board of Directors. However, the effect of the Rights may be to discourage a third party from making a partial tender offer or otherwise attempting to obtain a substantial equity position in the equity securities of, or seeking to obtain control of, PG&E Corporation. To the extent any potential acquirers are deterred by the Rights, the Rights may have the effect of preserving incumbent management in office.

Preferred Stock of Utility

The Utility has authorized 75 million shares of $25 par value preferred stock, which may be issued as redeemable or non-redeemable preferred stock. At December 31, 2001, and 2000, the Utility had issued and outstanding 5,784,825 shares of non-redeemable preferred stock.

At December 31, 2001, and 2000, the Utility had issued and outstanding 5,973,456 shares of redeemable preferred stock. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. Annual dividends and redemption prices per share at December 31, 2001, range from $1.09 to $1.76 and from $25.75 to $27.25, respectively.

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

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

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

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

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and equal preference in dividend and liquidation rights. Accumulated and unpaid preferred stock dividends amounted to $25 million as of December 31, 2001. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. Until cumulative dividends on its preferred stock are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

Preferred Stock of PG&E NEG

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

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

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

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

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

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

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

Note 9: Long-Term Debt

Long-term debt consisted of the following:

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

PG&E Corporation

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

common stock dividend. Further, approximately $99 million was used to pre-pay the first year's interest under the credit agreement and to pay transaction expenses associated with the debt restructuring.

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

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

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

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

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

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

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

Utility

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

First and Refunding Mortgage Bonds

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

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

Senior Notes

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

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

Pollution Control Loan Agreements

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

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

Medium-Term Notes

The Utility has outstanding $287 million of medium-term notes due from 2001 to 2014 with interest rates ranging from 5.81 percent to 8.45 percent, which are also in default. Accordingly, the amount outstanding at

December 31, 2001, and 2000, were classified as Liabilities Subject to Compromise in the accompanying financial statements.

PG&E NEG

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

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

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

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

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

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

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

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

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

Repayment Schedule

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

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

Note 10: Rate Reduction Bonds

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

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

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

At December 31, 2001, and 2000, $1,740 million and $2,030 million of Rate Reduction Bonds were outstanding, respectively. The principal payments on the Rate Reduction Bonds for the years 2002 through 2006 are $290 million for each year. While LLC is a wholly owned consolidated subsidiary of the Utility, LLC is legally separate from the Utility. The assets of LLC are not available to creditors of the Utility or PG&E Corporation, and the transition property is not legally an asset of the Utility or PG&E Corporation.

Note 11: Credit Facilities and Short-Term Borrowings

At December 31, 2001, and 2000, PG&E Corporation had borrowed $3,995 million and $5,191 million, respectively, through short-term borrowings and various credit facilities. At December 31, 2001, and 2000, $160 million and $661 million, respectively, of these borrowings were outstanding balances related to PG&E NEG's credit facilities, which are classified as long-term debt because PG&E NEG has the ability and intent to finance the amounts outstanding on a long-term basis. Due to the Utility's bankruptcy filing (see Note 2), pre-petition credit facilities at December 31, 2001, and 2000, of $938 million and $614 million, respectively, and short-term

borrowings of $2,567 million and $2,465 million, respectively, have been classified as Liabilities Subject to Compromise in the table below and on the Consolidated Balance Sheets for 2001. Amounts listed as Credit Facilities and Short-Term Borrowings as of December 31, 2000, were reclassified from their current status in the prior year for comparison purposes in the table below. The weighted average interest rate on the short-term borrowings as of December 31, 2001, and 2000, was 3.78 percent and 7.06 percent, respectively. The weighted average interest rate on the short-term borrowings subject to compromise as of December 31, 2001, and 2000, was 7.53 percent and 7.51 percent, respectively. The weighted average on the 2000 short-term borrowings subject to compromise is presented for comparison purposes. The following table summarizes PG&E Corporation's lines of credit.

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

PG&E Corporation

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

Utility

Credit Facility

As of December 31, 2000, the Utility had a $1 billion revolving credit facility which was scheduled to expire in December 2002. In October 2000, the Utility obtained an additional $1 billion credit facility, which was

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

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

Commercial Paper

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

Floating Rate Notes

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

Bank Borrowing – Letters of Credit for Accelerated Pollution Control Bonds

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

PG&E NEG

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

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

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

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

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

Note 12: Nuclear Decommissioning

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

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

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

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

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

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

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

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

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

Note 13: Employee Benefit Plans

Pension and Other Benefits

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

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

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

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

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

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

Net benefit income (cost) was as follows:

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

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

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

Net benefit income (cost) was calculated using expected return on plan assets of 8.5 percent for both pension and other benefits. The difference between actual and expected return on plan assets is included in net amortization and deferral and is considered in the determination of future net benefit income (cost). In 1999, actual return on plan assets exceeded expected return, while actual return on plan assets was below that expected in 2001 and 2000.

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

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

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

The assumed health care cost trend rate for 2002 is approximately 7.5 percent, grading down to an ultimate rate in 2005 and beyond of approximately 6 percent. The assumed health care cost trend rate can have a

significant effect on the amounts reported for health care plans. A 1-percentage point change would have the following effects:

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

Defined Contribution 401(k) Benefits

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

Long-Term Incentive Program

PG&E Corporation maintains a Long-Term Incentive Program (Program) that permits various stock-based incentive awards to be granted to non-employee directors, executive officers, and other employees of the PG&E Corporation and its subsidiaries. The Stock Option Plan, the Performance Unit Plan, and the Non-Employee Director Stock Incentive Plan (each of which is a component of the Program) provide incentives based on PG&E Corporation's financial performance over time.

Stock Option Plan (SOP)

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

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

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

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

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

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

Performance Unit Plan (PUP)

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

Non-Employee Director Stock Incentive Plan (NEDSIP)

Under the NEDSIP, each person who is a non-employee director on the first business day of the applicable calendar year is entitled to receive stock-based grants with a total aggregate equity value of $30,000, composed of (1) restricted shares of PG&E Corporation common stock valued at $10,000 (based on the closing price of PG&E Corporation common stock on the first business day of the year), and (2) a combination of non-qualified stock options and common stock equivalents with a total equity value of $20,000, based on equity value increments of $5,000. The exercise price of stock options is equal to the fair market value of PG&E Corporation common stock on the date of grant. Restricted stock and stock options vest over a five-year period following the date of grant, except upon a director's mandatory retirement from the Board at age 70, upon a director's death or disability, or in the event of a change in control, in which cases the restricted stock and stock options will vest immediately. The component of the NEDSIP representing stock options at December 31, 2001, 2000, and 1999, is included in the above data under Stock Option Plan (SOP) in accordance with SFAS No. 123 and APB No. 25. The component of the NEDSIP representing expense recognized in connection with issuance of restricted stock and common stock equivalents during the years ended December 31, 2001, 2000, and 1999, was not material.

PG&E Corporation Supplemental Retirement Savings Plan (SRSP)

The SRSP provides supplemental retirement alternatives to eligible senior officers and key employees of PG&E Corporation and its subsidiaries by allowing participants to defer portions of their compensation, including salaries, amounts awarded under the PUP, and other incentive awards. The SRSP also provides a means for eligible participants to receive and invest employer contribution amounts exceeding contribution limits within the various defined contribution plans sponsored by PG&E Corporation and its subsidiaries. Under the employee-elected deferral component of the SRSP, an eligible employee may defer all or part of his or her PUP (if eligible) and other incentive awards, and 5 to 50 percent of his or her monthly salary each month. Under the supplemental employer- provided retirement benefits component of the SRSP, eligible employees receive full employer matching and basic contributions in excess of limitations set out by the Internal Revenue Code as qualified under defined contribution

401(k) plans into a non-qualified account. A separate non-qualified account is maintained for each eligible employee to hold any deferred and/or employer-contributed amounts with investment options available for the employee's designation. PG&E Corporation recognizes any gain or loss from these investments and adjusts each employee account on a quarterly basis. Expense related to deferred amounts is recognized in the period in which it is earned by the employee and accrued until paid under the terms of the plan. Employer contribution expense and expenses related to gain or loss from investments of contributed and deferred amounts recognized in connection with the SRSP during the years ended December 31, 2001, 2000, and 1999, was not material.

Executive Stock Ownership Program (ESOP)

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

Retention Programs

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

Note 14: Income Taxes

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

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

The significant components of net deferred income tax liabilities were:

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

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

	PG&E Corporation			Utility		
	Year Ended December 31,			Year Ended December 31,		
	2001	2000	1999	2001	2000	1999
Federal statutory income tax rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit)	4.8	4.4	10.1	5.0	4.3	6.2
Effect of regulatory treatment of depreciation differences	1.6	(2.1)	51.7	1.7	(2.0)	9.4
Tax credits, net	(3.9)	0.7	(19.9)	(2.5)	0.7	(3.6)
Effect of foreign earnings at different tax rates	(0.1)	0.1	(1.3)	—	—	—
Stock sale differences	—	(1.4)	(6.8)	—	—	—
Stock sale valuation allowance	—	1.5	30.2	—	—	—
Other, net	(1.6)	(0.3)	(4.0)	(2.2)	0.2	(1.9)
Effective tax rate	35.8%	37.9%	95.0%	37.0%	38.2%	45.1%

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

of which $1.1 billion was refunded to the Utility.

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

Note 15: Commitments

Tolling Agreements

PG&E NEG

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

Estimated amounts payable in future years are as follows:

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

Power Purchase Contracts

Utility

Qualifying Facilities, Irrigation Districts, and Water Agencies

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

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

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

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

the principal amount of the pre-petition debt per month until the effective date of the Utility's plan of reorganization or until July 15, 2005, when it will pay the remaining pre-petition debt.

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

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

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

The Utility also has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments, whether or not any energy is supplied (subject to the supplier's retention of the FERC's authorization), and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. Irrigation district and water agency deliveries in the aggregate account for approximately 3 percent of the Utility's 2001 electric energy requirements.

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

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

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

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

Bilateral Contracts

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

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

PG&E NEG

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

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

Natural Gas Supply and Transportation Commitments

Utility

Under current CPUC regulations, the Utility purchases natural gas from its various suppliers based on economic considerations, consistent with regulatory, contractual, and operational constraints. The Utility has long-term gas transportation service agreements with various Canadian and interstate pipeline companies. The total demand charges that the Utility will pay each year may change due to changes in tariff rates. These agreements include provisions for payment of fixed demand charges for reserving firm capacity on the pipelines. The total demand and volumetric transportation charges the Utility incurred under these agreements were $239 million, $94 million, and $97 million in 2001, 2000, and 1999, respectively. These amounts include payments made by the Utility to PG&E GTN of $41 million, $46 million, and $47 million in 2001, 2000, and 1999, respectively, which are eliminated in the consolidated financial statements of PG&E Corporation.

The Utility also has long-term gas supply contracts with various Canadian and interstate gas companies. The contracts commit the Utility to purchase gas through October 2002, and total $260 million. On January 31, 2001, the CPUC authorized the Utility to pledge its gas accounts receivables and its gas inventories for up to 90 days (subsequently extended to 180 days and expiring on May 1, 2002), and at December 31, 2001, total gas accounts

receivable pledged amounted to $268 million. At December 31, 2001, the Utility's obligations related to natural gas transportation and supply commitments held pursuant to long-term contracts are as follows:

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

PG&E NEG

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

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

Turbine Purchase Commitments

PG&E NEG

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

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

Out-of-Market Contractual Commitments

PG&E NEG

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

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

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

Long-Term Receivables

PG&E NEG

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

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

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

Operating Leases

Utility

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

(in millions)	
2002	$ 11
2003	11
2004	12

2005	12
2006	11
Thereafter	18
Total	$ 75

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

PG&E NEG

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

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

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

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

Nuclear Fuel Agreements

Utility

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

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

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

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

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

WAPA Sales Contract Commitments

Utility

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

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

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

Other Commitments

Utility

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

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

PG&E NEG

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

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

Note 16: Contingencies

Nuclear Insurance

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

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

Surety Bonds

Utility

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

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

Environmental Remediation

Utility

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

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

Hazardous Waste Remediation

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

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

- Up to $22 million in each calendar year in which the Chapter 11 case is pending to continue its hazardous substance remediation programs and procedures; and

- Any additional amounts necessary in emergency situations involving post-petition releases or threatened releases of hazardous substances subject to the Bankruptcy Court's specific approval.

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

Environmental Claims

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

Moss Landing

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

Diablo Canyon

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

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

PG&E NEG

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

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

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

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

Guarantees

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

Guarantees Supporting Tolling Agreements

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

Guarantees Supporting Agreements with Third Parties

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

Guarantees Supporting Trading Related Agreements

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

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

The continued acceptability of many of these guarantees is dependent on PG&E NEG's maintaining various standards of creditworthiness. As a result, maintenance of investment grade ratings by one or more rating agencies is an important criterion for PG&E NEG and its subsidiaries. If PG&E NEG or its subsidiaries are downgraded by one or more of the rating agencies, PG&E NEG may be required to provide alternative collateral to replace

guarantees that no longer meet the creditworthiness standards of the agreements. Therefore, PG&E NEG and its trading subsidiaries maintain substantial cash balances and credit capacity to provide liquidity to its businesses in the event that open credit limits are exceeded through volatility, or in the event of a credit downgrade.

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

Legal Matters

Utility

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

Chromium Litigation

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

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

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

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

Natural Gas Royalties Litigation

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

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

The complaints allege that the various defendants (most of which are pipeline companies or their affiliates) incorrectly measured the volume and heat content of natural gas produced from federal or Indian leases. As a result, it is alleged that the defendants underpaid, or caused others to underpay, the royalties that were due to the United States for the production of natural gas from those leases. The complaints do not seek a specific dollar

amount or quantify the royalties claim. The complaints seek unspecified treble damages, civil penalties, and expenses associated with the litigation.

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

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

Federal Securities Lawsuit

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

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

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

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

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

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

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

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

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

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

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

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

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

On February 27, 2002, a group of 25 ratepayers filed a complaint against the Utility at the CPUC demanding an immediate reduction of approximately $0.0 35 per kWh in allegedly excessive electric rates and a refund of alleged recent overcollections in electric revenue since June 1, 2001. The complaint claims that electric rate surcharges adopted in the first quarter of 2001 due to the high cost of wholesale power, surcharges that increased the average electric rate by $0.04 per kWh, became excessive later in 2001. (In January 2001, the CPUC authorized a $0.01 per kWh increase to pay for energy procurement costs. In March 2001, the CPUC authorized an additional $0.03 per kWh electric rate increase as of March 27, 2001, to pay for energy procurement costs, which the Utility began to collect in June 2001.) The only alleged over-collection amount calculated in the complaint is approximately $400 million during the last quarter of 2001. The complaint has not yet been served on the Utility. The Utility's answer will be due 30 days after the date of service of the complaint.

Recorded Liability for Legal Matters

In accordance with SFAS No. 5, "Accounting for Contingencies," PG&E Corporation makes a provision for a liability when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, settlements, rulings, advice of legal counsel, and other information and events pertaining to a particular case. The following table reflects the current and prior year's activity to the recorded liability for legal matters for PG&E Corporation and the Utility:

(in millions)	2001	2000
Beginning balance, January 1,	$ 185	$ 106
Provisions for liabilities	7	144
Payments	(2)	(45)

Adjustments	19	(20)
Ending balance, December 31,	$ 209	$ 185

Note 17: Segment Information

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

Utility

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

PG&E NEG

PG&E NEG accounts for its business in two reportable segments. PG&E Energy reflects the integration of PG&E NEG's generation, development, and energy marketing and trading activities. PG&E Pipeline consists principally of the operations of its interstate natural gas transmission pipeline which runs from the Canada/United States border to the California/Oregon border. PG&E GTT was also part of the PG&E Pipeline segment prior to its sale in December 2000. Finally, in 2000, PG&E NEG disposed of its energy services unit, PG&E ES.

Segment information for the years 2001, 2000, and 1999, is as follows:

(in millions)	Utility	PG&E National Energy Group [6] Total PG&E NEG [7]	Integrated Energy & Marketing	Interstate Pipeline Operations	PG&E NEG Eliminations	PG&E Corporation Eliminations & Others [3]	Total
2001							
Operating revenues	$ 10,450	$ 12,509	$ 12,362	$ 153	$ (6)	$ —	$ 22,959
Intersegment revenues [1]	12	160	67	93	—	(172)	—
Total operating revenues	10,462	12,669	12,429	246	(6)	(172)	22,959
Depreciation, amortization, and decommissioning	896	167	120	42	5	5	1,068
Interest income	123	86	71	7	8	4	213
Interest expense	(974)	(138)	(75)	(37)	(26)	(101)	(1,213)
Income taxes (benefits) [2]	596	57	26	34	(3)	(45)	608
Income (loss) from continuing operations	990	174	102	76	(4)	(74)	1,090
Net income (loss)	990	183	111	76	(4)	(74)	1,099
Capital expenditures	1,343	1,318	1,216	102	—	4	2,665
Total assets at year-end [4]	25,137	10,329	8,922	1,251	156	396	35,862
2000 [5]							
Operating revenues	9,623	16,597	15,525	1,066	6	—	26,220
Intersegment revenues [1]	14	182	136	46	—	(196)	—
Total operating revenues	9,637	16,779	15,661	1,112	6	(196)	26,220
Depreciation, amortization, and decommissioning	3,511	143	102	41	—	5	3,659
Interest income	186	80	78	(3)	5	—	266
Interest expense	(619)	(155)	(64)	(90)	(1)	(14)	(788)
Income taxes (benefits) [2]	(2,154)	130	97	37	(4)	(4)	(2,028)
Income (loss) from continuing operations	(3,508)	192	104	78	10	(8)	(3,324)
Net income (loss)	(3,508)	152	104	78	(30)	(8)	(3,364)
Capital expenditures [7]	1,245	1,101	1,086	15	—	0	2,346
Total assets at year-end [4]	21,988	13,967	12,419	1,204	344	197	36,152
1999 [5]							
Operating revenues	9,084	11,735	10,402	1,325	8	—	20,819
Intersegment revenues [1]	144	77	30	47	—	(221)	—
Total operating revenues	9,228	11,812	10,432	1,372	8	(221)	20,819
Depreciation, amortization, and decommissioning	1,564	213	97	116	—	3	1,780
Interest income	45	74	66	8	—	(1)	118
Interest expense	(593)	(176)	(76)	(100)	—	(3)	(772)
Income taxes (benefits) [2]	648	(394)	(16)	(375)	(3)	(6)	248
Income (loss) from continuing operations	763	(750)	68	(829)	11	—	13
Net income (loss)	763	(836)	80	(829)	(87)	—	(73)
Capital expenditures [7]	1,181	520	454	49	17	—	1,701
Total assets at year-end [4]	21,470	8,554	5,846	2,377	331	(436)	29,588

(1) Inter-segment revenues are recorded at market prices, which for the Utility and PG&E Pipeline are tariffed rates prescribed by the CPUC and the FERC, respectively.

(2) Income tax expense for the Utility is computed on a stand-alone basis. The balance of the consolidated income tax provision is allocated among PG&E Corporation and the PG&E National Energy Group.

(3) Includes PG&E Corporation, PG&E Ventures, LLC and elimination entries.

(4) Assets of PG&E Corporation are included in the "PG&E Corporation, Eliminations and Others" column exclusive of investment in its subsidiaries.

(5) Segment information for the prior years has been restated for comparative purposes as required by SFAS No. 131.

(6) Income from equity-method investees for 2001, 2000, and 1999, was $79 million, $65 million, and $63 million respectively, for PG&E Gen, and $1 million in 2000, and $0 in 1999, for PG&E GTT.

(7) Capital expenditures and assets of the discontinued operations of PG&E ES are included in the "PG&E Corporation, Eliminations and Others" column. Total assets for PG&E ES at December 31, 2001, 2000, and 1999, were $0, $1 million, and $197 million, respectively. Capital expenditures for 2001, 2000, and 1999, were $0, $0, and $17 million, respectively.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

Quarter ended (in millions, except per share amounts)	December 31	September 30	June 30	March 31
2001				
PG&E Corporation				
Operating revenues	$ 4,978	$ 6,298	$ 5,010	$ 6,673
Operating income (loss)	1,077	1,552	1,447	(1,340)
Income (loss) from continuing operations	520	771	750	(951)
Net income (loss)	529	771	750	(951)
Earnings (Loss) per common share, basic	1.46	2.12	2.07	(2.62)
Earnings (Loss) per common share, diluted	1.45	2.12	2.07	(2.62)
Common stock price per share				
High	20.10	17.45	12.54	20.94
Low	14.96	11.66	6.50	8.38
Utility				
Operating revenues	$ 2,654	$ 2,937	$ 2,309	$ 2,562
Operating income (loss)	1,134	1,428	1,336	(1,420)
Net income (loss)	563	744	702	(994)
Income (Loss) available for (allocated to) common stock	557	737	696	(1,000)
2000				
PG&E Corporation				
Operating revenues	$ 8,079	$ 7,502	$ 5,637	$ 5,002
Operating income (loss) [1][2]	(6,734)	629	622	676
Income (Loss) from continuing operations	(4,096)	244	248	280
Net income (loss) [1] [2]	(4,117)	225	248	280
Earnings (Loss) per common share from continuing operations, basic	(11.28)	0.67	0.69	0.78
Earnings (Loss) per common share from continuing operations, diluted	(11.28)	0.67	0.68	0.77
Dividends declared per common share	0.30	0.30	0.30	0.30
Common stock price per share				
High	29.50	31.81	27.75	23.13
Low	17.00	22.31	20.63	19.69
Utility				
Operating revenues	$ 2,600	$ 2,523	$ 2,296	$ 2,218
Operating income (loss)	(6,856)	533	552	570
Net income (loss)	(4,156)	217	222	234
Income (Loss) available for (allocated to) common stock	(4,163)	211	216	228

[1] In the third quarter of 2000, an estimated loss of $19 million ($0.05 per share), net of income taxes of $13 million, was recorded related to the disposal of PG&E ES. In the fourth quarter of 2000, an additional estimated loss of $21 million ($0.06 per share), net of income taxes of $23 million, also was recorded related to the disposal of PG&E ES.

[2] In the fourth quarter of 2000, the Utility recorded a charge to earnings for the write-off of regulatory assets representing transition costs and under-collected purchased power costs. The write-off was $6.9 billion ($4.1 billion after tax) and reflected the fact that, based upon the current status of the California energy crisis, the Utility could no longer conclude that the regulatory assets were probable of recovery through regulated rates. Also, in the fourth quarter of 2000, the Utility recognized a $140 million ($83 million, after tax) provision for an increase in legal reserves.

INDEPENDENT AUDITORS' REPORT

To the Boards of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries and Pacific Gas and Electric Company (a Debtor-in-Possession) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, cash flows and common stockholders' equity of PG&E Corporation and the related statements of consolidated operations, cash flows and stockholders' equity of Pacific Gas and Electric Company (a Debtor-in-Possession) for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the management of PG&E Corporation and of Pacific Gas and Electric Company. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such 2001 and 2000 consolidated financial statements present fairly, in all material respects, the consolidated financial position of PG&E Corporation and Pacific Gas and Electric Company as of December 31, 2001 and 2000, and the results of their consolidated operations and cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 of the Notes to the Consolidated Financial Statements, PG&E Corporation and Pacific Gas and Electric Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by Statement of Financial Accounting Standards No. 138, "Accounting for Certain Derivatives and Hedging Activities," effective January 1, 2001, and interpretations issued by the Derivatives Implementation Group of the Financial Accounting Standards Board during 2001, and in 1999, PG&E Corporation changed its method of accounting for major maintenance and overhauls.

The accompanying consolidated financial statements have been prepared on a going concern basis of accounting. As discussed in Notes 2 and 3 of the Notes to the Consolidated Financial Statements, Pacific Gas and Electric Company, a subsidiary of PG&E Corporation, has incurred power purchase costs substantially in excess of amounts charged to customers in rates. On April 6, 2001, Pacific Gas and Electric Company sought protection from its creditors by filing a voluntary petition under provisions of Chapter 11 of the U.S. Bankruptcy Code. These matters raise substantial doubt about Pacific Gas and Electric Company's ability to continue as a going concern. Managements' plans in regard to these matters are also described in Notes 2 and 3 of the Notes to the Consolidated Financial Statements. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

DELOITTE & TOUCHE LLP
San Francisco, California
March 1, 2002

RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

PG&E Corporation and Pacific Gas and Electric Company (the Utility) management are responsible for the integrity of the accompanying consolidated financial statements. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. Management considers materiality and uses its best judgment to ensure that such statements reflect fairly the financial position, results of operations, and cash flows of PG&E Corporation and the Utility.

PG&E Corporation and the Utility maintain systems of internal controls supported by formal policies and procedures, which are communicated throughout PG&E Corporation and the Utility. These controls are adequate to provide reasonable assurance that assets are safeguarded from material loss or unauthorized use and that necessary records are produced for the preparation of consolidated financial statements. There are limits inherent in all systems of internal controls, based on recognition that the costs of such systems should not exceed the benefits to be derived. PG&E Corporation and the Utility believe that their systems of internal control provide this appropriate balance. PG&E Corporation management also maintains a staff of internal auditors who evaluate the adequacy of, and assess the adherence to, these controls, policies, and procedures for all of PG&E Corporation, including the Utility.

Both PG&E Corporation's and the Utility's consolidated financial statements included herein have been audited by Deloitte & Touche LLP, PG&E Corporation's independent auditors. The audit includes consideration of internal accounting controls and performance of tests necessary to support an opinion. The auditors' report contains an independent informed judgment as to the fairness, in all material respects, of reported results of operations and financial position.

The Audit Committee of the Board of Directors of PG&E Corporation meets regularly with management, internal auditors, and Deloitte & Touche LLP, jointly and separately, to review internal accounting controls and auditing and financial reporting matters. The internal auditors and Deloitte & Touche LLP have free access to the Audit Committee, which consists of five outside directors. The Audit Committee has reviewed the financial data contained in this report.

PG&E Corporation and the Utility are committed to full compliance with all laws and regulations and to conducting business in accordance with high standards of ethical conduct. Management has taken the steps necessary to ensure that all employees and other agents understand and support this commitment. Guidance for corporate compliance and ethics is provided by an officers' Ethics Committee and by a Legal Compliance and Business Ethics organization. PG&E Corporation and the Utility believe that these efforts provide reasonable assurance that each of their operations is conducted in conformity with applicable laws and with their commitment to ethical conduct.

Exhibit 21

PG&E Corporation and Pacific Gas and Electric Company Subsidiaries

	State
PG&E Corporation	CA
Elm Power Corporation	DE
Pacific Gas and Electric Company	CA
201 Turk Street, L.P.	CA
1989 Oakland Housing Partnership Associates, L.P.	CA
1992 Oakland Regional Housing Partnership Associates, a California Limited Partnership	CA
1994 Oakland Regional Housing Partnership Associates, a California Limited Partnership	CA
Alberta and Southern Gas Co. Ltd.	AB(Can)
Calaska Energy Company	CA
Chico Commons, a California Limited Partnership	CA
Eureka Energy Company	CA
Merritt Community Capital Fund V, L.P.	CA
Natural Gas Corporation of California	CA
Alaska Gas Exploration Associates	CA
NGC Production Company	CA
Newco Energy Corporation	CA
Electric Generation LLC	CA

Balch 1 and 2 Project LLC	CA
Battle Creek Project LLC	CA
Bucks Creek Project LLC	CA
Chili Bar Project LLC	CA
Crane Valley Project LLC	CA
DeSabla-Centerville Project LLC	CA
Diablo Canyon LLC	CA
Drum-Spaulding Project LLC	CA
Haas-Kings River Project LLC	CA
Hamilton Branch Project LLC	CA
Hat Creek 1 and 2 Project LLC	CA
Helms Project LLC	CA
Kerckhoff 1 and 2 Project LLC	CA
Kern Canyon Project LLC	CA
Kilarc-Cow Creek Project LLC	CA
McCloud-Pit Project LLC	CA
Merced Falls Project LLC	CA
Miocene Project LLC	CA
Mokelumne River Project LLC	CA
Narrows Project LLC	CA
Phoenix Project LLC	CA
Pit 1 Project LLC	CA
Pit 3, 4 and 5 Project LLC	CA
Poe Project LLC	CA
Potter Valley Project LLC	CA
Rock Creek-Cresta Project LLC	CA
Spring-Gap Stanislaus Project LLC	CA
Tule River Project LLC	CA
Upper NF Feather River Project LLC	CA
ETrans LLC	CA
GTrans LLC	CA
Pacific California Gas System, Inc.	CA
Pacific Conservation Services Company	CA
Pacific Energy Fuels Company	CA
Pacific Gas and Electric Housing Fund Partnership, L.P.	CA
Pacific Gas Properties Company	CA
Pacific Properties	CA
PG&E CalHydro, LLC	CA
PG&E Capital I	DE
PG&E Capital II	DE
PG&E Capital III	DE

Some entities appear more than once because entities which are owned by more than one subsidiary are listed under each owner.

PG&E Corporation and Pacific Gas and Electric Company Subsidiaries

	State
PG&E Capital IV	DE
PG&E Funding LLC	DE
PG&E Holdings, LLC	DE
Schoolhouse Lane Apartments L.P.	CA
Standard Pacific Gas Line Incorporated	CA
PG&E Corporation Support Services, Inc.	DE
PG&E National Energy Group, LLC	DE
PG&E National Energy Group, Inc.	DE
PG&E Enterprises	CA
PG&E National Energy Group Holdings Corporation	CA
Citrus Generating Company, L.P.	DE
Properties Holdings, LLC	DE
Alhambra Pacific Joint Venture	CA
BPS I, Inc.	CA
Alhambra Pacific Joint Venture	CA
Conaway Ranch Company, The	CA
Conaway Conservancy Group Joint Venture	CA
Conaway Conservancy Group Joint Venture	CA
DPR, Inc.	CA
Gilia Enterprises	CA
Marengo Ranch Joint Venture	CA
Oat Creek Associates Joint Venture	CA
Marengo Ranch Joint Venture	CA
Oat Creek Associates Joint Venture	CA
Valley Real Estate, Inc.	CA
PG&E Energy Trading Holdings, LLC	DE
PG&E Energy Trading Holdings Corporation	CA
PG&E Energy Trading – Power, L.P.	DE
PG&E ET Synfuel 166, LLC	DE
PG&E ET Synfuel #2, LLC	DE
PG&E ET Investments Corporation	DE
PG&E Energy Trading – Power, L.P.	DE
PG&E Energy Trading – Gas Corporation	CA
PG&E Energy Trading, Canada Corporation	AB (Can)
CEG Energy Options, Inc.	SK (Can)
True Quote LLC	KY
Virtual Credit Services, LLC	DE
PG&E International, Inc.	CA
PG&E International Development Holdings, LLC	DE
PG&E Overseas Holdings I, Ltd.	Cayman Is.
PG&E Overseas Holdings II, Ltd.	Cayman Is.
PG&E Corporation Australian Holdings Pty Ltd.	Australia
PG&E Corporation Australia Pty Ltd.	Australia
PG&E Energy Trading Australia Pty Ltd.	Australia
Gannet Power Corporation	CA
Rocksavage Services I, Inc.	DE
PG&E Generating Company, LLC	DE
PG&E Generating Energy Group, LLC	DE
Attala Power Corporation	DE
Attala Generating Company, LLC	DE
Attala Energy Company, LLC	DE
Badger Power Corporation	DE
Badger Generating Company, LLC	DE
Beech Power Corporation	DE
Mantua Creek Generating Company, L.P.	DE
Mantua Creek Urban Renewal, L.P.	DE

Some entities appear more than once because entities which are owned by more than one subsidiary are listed under each owner.

PG&E Corporation and Pacific Gas and Electric Company Subsidiaries

	State
Plover Power Corporation	CA
Mantua Creek Generating Company, L.P.	DE
Mantua Creek Urban Renewal, L.P.	DE
Black Hawk III Power Corporation	CA
Lake Road Generating Company, L.P.	DE
Lake Road Power I, LLC	DE
Peach IV Power Corporation	DE
Lake Road Generating Company, L.P.	DE
Lake Road Power II, LLC	DE
Bluebonnet Power Corporation	DE
Bluebonnet Generating Company, LLC	DE
Covert Power Corporation	DE
Covert Generating Company, LLC	DE
First Arizona Land Corporation	DE
First California Land Corporation	DE
GenHoldings I, LLC	DE
Black Hawk Power Corporation	CA
Athens Generating Company, L.P.	DE
Harquahala Generating Company, LLC	DE
Harquahala Power Corporation	DE
Harquahala Generating Company, LLC	DE
Osprey Power Corporation	CA
Millennium Power Partners, L.P.	DE
Magnolia Power Corporation	DE
Millennium Power Partners, L.P.	DE
Peach I Power Corporation	DE
Athens Generating Company, L.P.	DE
Goose Lake Power Corporation	DE
Goose Lake Generating Company, LLC	DE
Harlan Power Corporation	CA
Umatilla Generating Company, L.P.	DE
Juniper Power Corporation	DE
Umatilla Generating Company, L.P.	DE
Long Creek Power Corporation	DE
Long Creek Generating Company, LLC	DE
Kentucky Hydro Holdings, LLC	DE
La Paloma Power Corporation	DE
La Paloma Generating Company, LLC	DE
Liberty Generating Corporation	DE
Liberty Generating Company, LLC	DE
Liberty Urban Renewal, LLC	DE
Madison Wind Power Corporation	DE
Madison Windpower LLC	DE
Meadow Valley Power Corporation	DE
Meadow Valley Generating Company, LLC	DE
MidColumbia Power Corporation	DE
MidColumbia Generating Company, LLC	DE
Morrow Power Corporation	DE
Morrow Generating Company, LLC	DE
Okeechobee Power Corporation	DE
Okeechobee Generating Company, LLC	DE
Otay Mesa Power Corporation	DE
PG&E Dispersed Power Corporation	DE
PG&E Dispersed Generating Company, LLC	DE
Plains End, LLC	DE
PG&E Generating Energy Holdings, Inc.	DE
Badger Generating Company, LLC	DE
Bluebonnet Generating Company, LLC	DE

Some entities appear more than once because entities which are owned by more than one subsidiary are listed under each owner.

PG&E Corporation and Pacific Gas and Electric Company Subsidiaries

	State
Covert Generating Company, LLC	DE
Goose Lake Generating Company, LLC	DE
Long Creek Generating Company, LLC	DE
La Paloma Generating Company, LLC	DE
Liberty Generating Company, LLC	DE
Liberty Urban Renewal, LLC	DE
Madison Windpower LLC	DE
Meadow Valley Generating Company, LLC	DE
MidColumbia Generating Company, LLC	DE
Morrow Generating Company, LLC	DE
Okeechobee Generating Company, LLC	DE
PG&E Dispersed Generating Company, LLC	DE
Spencer Station Generating Company, L.P.	DE
PG&E Generating New England, Inc.	DE
PG&E Generating New England, LLC	DE
San Gorgonio Power Corporation	DE
Mountain View Power Partners, LLC	DE
Mountain View Power Partners II, LLC	DE
Spencer Station Power Corporation	DE
Spencer Station Generating Company, L.P.	DE
USGen New England, Inc.	DE
First Massachusetts Land Company, LLC	DE
USGen Services Company, LLC	DE
White Pine Generating Company, LLC	DE
PG&E Generating Power Group, LLC	DE
Aplomado Power Corporation	CA
Beale Generating Company	DE
Indian Orchard Generating Company, Inc.	DE
MASSPOWER, L.L.C.	DE
MASSPOWER	MA
JMC Altresco, Inc.	CO
Altresco, Inc.	CO
Pittsfield Generating Company, L.P.	DE
Berkshire Pittsfield, Inc.	CO
Berkshire Feedline Acquisition Limited Partnership	MA
Pittsfield Partners, Inc.	CO
Pittsfield Generating Company, L.P.	DE
JMC Iroquois, Inc.	DE
Iroquois Gas Transmission System, L.P.	DE
JMC Selkirk Holdings, Inc.	DE
JMC Selkirk, Inc.	DE
PentaGen Investors, L.P.	DE
Selkirk Cogen Partners, L.P.	DE
Selkirk Cogen Funding Corporation	DE
Selkirk Cogen Partners, L.P.	DE
Selkirk Cogen Funding Corporation	DE
JMCS I Holdings, Inc.	DE
PentaGen Investors, L.P.	DE
Selkirk Cogen Partners, L.P.	DE
Selkirk Cogen Funding Corporation	DE
Orchard Gas Corporation	DE
Mason Generating Company	DE
J. Makowski Associates, Inc.	MA
Cooper’s Hawk Power Corporation	CA
Citrus Generating Company, L.P.	DE
Eucalyptus Power Corporation	DE
Citrus Generating Company, L.P.	DE
Eagle Power Corporation	CA

Some entities appear more than once because entities which are owned by more than one subsidiary are listed under each owner.

PG&E Corporation and Pacific Gas and Electric Company Subsidiaries

	State
Granite Generating Company, L.P.	DE
Granite Water Supply Company, Inc.	DE
Keystone Urban Renewal Limited Partnership	DE
Keystone Cogeneration Company, L.P.	DE
Keystone Urban Renewal Limited Partnership	DE
Logan Generating Company, L.P.	DE
Falcon Power Corporation	CA
Scrubgrass Generating Company, L.P.	DE
Scrubgrass Power Corp.	PA
Scrubgrass Generating Company, L.P.	DE
Clearfield Properties, Inc.	DE
Leechburg Properties, Inc.	DE
Spruce Power Corporation	DE
Spruce Limited Partnership	DE
Colstrip Energy, Limited Partnership	MT
Heron Power Corporation	CA
Gator Generating Company, L.P.	DE
Iroquois Pipeline Investment, LLC	DE
Iroquois Gas Transmission System, L.P.	DE
Jaeger Power Corporation	CA
Northampton Generating Company, L.P.	DE
Northampton Fuel Supply Company, Inc.	DE
Northampton Water Supply, Inc.	DE
Larkspur Power Corporation	DE
Hermiston Generating Company, L.P.	DE
Buckeye Power Corporation	DE
Hermiston Generating Company, L.P.	DE
Loon Power Corporation	DE
Merlin Power Corporation	CA
Fellows Generating Company, L.P.	DE
Pelican Power Corporation	CA
Okeelanta Power Limited Partnership	DE
Peregrine Power Corporation	CA
Chambers Cogeneration, Limited Partnership	DE
Raptor Holdings Company	CA
Gray Hawk Power Corporation	DE
Cedar Bay Cogeneration, Inc.	DE
Cedar Bay Generating Company, Limited Partnership	DE
PG&E Management Services Company	CA
Toyan Enterprises	CA
Indiantown Cogeneration, L.P.	DE
Indiantown Project Investment Partnership, L.P.	DE
Indiantown Cogeneration, L.P.	DE
Indiantown Cogeneration Funding Corporation	DE
PG&E Generating Services, LLC	DE
J. Makowski Pittsfield, Inc.	DE
J. Makowski Services, Inc.	DE
JMCS I Management, Inc.	DE
NEG Construction Finance Company, LLC	DE
PG&E Construction Agency Services I, LLC	DE
PG&E Construction Agency Services II, LLC	DE
PG&E National Energy Group Construction Company, LLC	DE
PG&E Operating Services Holdings, Inc.	CA
PG&E Operating Services Company	CA
PG&E National Energy Group Acquisition Company, LLC	DE
USGen Holdings, Inc.	DE
PG&E National Energy Group Company	CA
PG&E National Energy Group Company	CA

Some entities appear more than once because entities which are owned by more than one subsidiary are listed under each owner.

PG&E Corporation and Pacific Gas and Electric Company Subsidiaries

	State
First Oregon Land Corporation	DE
Garnet Power Corporation	DE
Carneys Point Generating Company	DE
Topaz Power Corporation	DE
Carneys Point Generating Company	DE
USOSC Holdings, Inc.	DE
PG&E Operating Services Company	CA
PTP Services, LLC	DE
PG&E Overseas, Inc.	CA
PG&E Overseas, Ltd.	Cayman Is
PG&E Pacific I, Ltd.	Cayman Is
PG&E Pacific II, Ltd.	Cayman Is
Quantum Ventures	CA
Barakat & Chamberlin, Inc.	CA
Creston Financial Group, Inc.	CA
PG&E Energy Services Ventures, Inc.	DE
Real Estate Energy Solutions, LLC	DE
PG&E Gas Transmission Corporation	CA
GTN Holdings LLC	DE
PG&E Gas Transmission, Northwest Corporation	CA
Pacific Gas Transmission Company	CA
Pacific Gas Transmission International, Inc.	CA
PG&E Gas Transmission Service Company LLC	DE
Stanfield Hub Services, LLC	WA
PG&E Gas Transmission Holdings Corporation	CA
North Baja Pipeline, LLC	DE
PG&E Strategic Capital, Inc.	DE
PG&E Ventures, LLC	DE
Pacific Venture Capital, LLC	DE
PG&E Ventures ePro, LLC	DE
PG&E Telecom, LLC	DE
PG&E Capital, LLC	DE
PG&E Telecom Holdings, LLC	DE

Some entities appear more than once because entities which are owned by more than one subsidiary are listed under each owner.

EXHIBIT 23

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statements No. 333–16255 and 333–25685 on Form S–3 and 333–16253, 333-27015, 333–68155, 333–46772, 333–77145, 333–77149 and 333–73054 on Form S–8 of PG&E Corporation and Registration Statements No. 33-64136, 33–50707, 33–62488 and 33–61959 on Form S-3 of Pacific Gas and Electric Company of our reports dated March 1, 2002 (which express an unqualified opinion and include an explanatory paragraph relating to items discussed in Notes 2 and 3 of the Notes to the Consolidated Financial Statements), appearing in and incorporated by reference in this Annual Report on Form 10-K of PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2001.

DELOITTE & TOUCHE LLP
San Francisco, California
March 5, 2002

EXHIBIT 24.1

RESOLUTION OF THE BOARD OF DIRECTORS OF PG&E CORPORATION

February 20, 2002

WHEREAS, the Audit Committee of this Board of Directors has reviewed the audited consolidated financial statements for this

corporation for the year ended December 31, 2001, and has recommended to the Board that such financial statements be included in the corporation's Annual Report on Form 10-K for the year ended December 31, 2001, to be filed with the Securities and Exchange Commission;

BE IT RESOLVED that each of LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES is hereby authorized to sign on behalf of this corporation and as attorneys in fact for the Chairman of the Board, Chief Executive Officer, and President, the Senior Vice President and Chief Financial Officer, and the Senior Vice President and Controller of this corporation the Form 10-K Annual Report for the year ended December 31, 2001, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and all amendments and other filings or documents related thereto to be filed with the Securities and Exchange Commission, and to do any and all acts necessary to satisfy the requirements of the Securities Exchange Act of 1934 and the regulations of the Securities and Exchange Commission adopted thereunder with regard to said Form 10-K Annual Report.

I, LINDA Y.H. CHENG, do hereby certify that I am Corporate Secretary of PG&E CORPORATION, a corporation organized and existing under the laws of the State of California; that the above and foregoing is a full, true, and correct copy of a resolution which was duly adopted by the Board of Directors of said corporation at a meeting of said Board which was duly and regularly called and held at the office of said corporation on February 20, 2002; and that this resolution has never been amended, revoked, or repealed, but is still in full force and effect.

WITNESS my hand and the seal of said corporation hereunto affixed this 20th day of February, 2002.

PG&E C ORPORATION

By: /s/ L INDA Y.H. C HENG

Linda Y.H. Cheng
Corporate Secretary

C O R P O R A T E

S E A L

RESOLUTION OF THE
BOARD OF DIRECTORS OF
PACIFIC GAS AND ELECTRIC COMPANY

February 20, 2002

WHEREAS, the Audit Committee of this Board of Directors has reviewed the audited consolidated financial statements for this company for the year ended December 31, 2001, and has recommended to the Board that such financial statements be included in the company's Annual Report on Form 10-K for the year ended December 31, 2001, to be filed with the Securities and Exchange Commission;

BE IT RESOLVED that each of LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES is hereby authorized to sign on behalf of this company and as attorneys in fact for the President and Chief Executive Officer, the Senior Vice President—Chief Financial Officer and Treasurer, and the Vice President—Controller of this company the Form 10-K Annual Report for the year ended December 31, 2001, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and all amendments and other filings or documents related thereto to be filed with the Securities and Exchange Commission, and to do any and all acts necessary to satisfy the requirements of the Securities Exchange Act of 1934 and the regulations of the Securities and Exchange Commission adopted thereunder with regard to said Form 10-K Annual Report.

I, LINDA Y.H. CHENG, do hereby certify that I am Corporate Secretary of PACIFIC GAS AND ELECTRIC COMPANY, a corporation organized and existing under the laws of the State of California; that the above and foregoing is a full, true, and correct copy of a resolution which was duly adopted by the Board of Directors of said corporation at a meeting of said Board which was duly and regularly called and held on February 20, 2002; and that this resolution has never been amended, revoked, or repealed, but is still in full force and effect.

WITNESS my hand and the seal of said corporation hereunto affixed this 20th day of February, 2002.

PACIFIC GAS AND ELECTRIC COMPANY

By: /s/ LINDA Y.H. CHENG

Linda Y.H. Cheng
Corporate Secretary

CORPORATE

SEAL

EXHIBIT 24.2

POWER OF ATTORNEY

Each of the undersigned Directors of PG&E Corporation hereby constitutes and appoints LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Form 10-K Annual Report for the year ended December 31, 2001, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 20th day of February, 2002.

/s/ DAVID R. ANDREWS

David R. Andrews

/s/ DAVID M. LAWRENCE, MD

David M. Lawrence, MD

/s/ DAVID A. COULTER

David A. Coulter

/s/ MARY S. METZ

Mary S. Metz

/s/ C. LEE COX

C. Lee Cox

/s/ CARL E. REICHARDT

Carl E. Reichardt

/s/ WILLIAM S. DAVILA

William S. Davila

/s/ BARRY LAWSON WILLIAMS

Barry Lawson Williams

/s/ ROBERT D. GLYNN, JR.

Robert D. Glynn, Jr.

POWER OF ATTORNEY

ROBERT D. GLYNN, JR., the undersigned, Chairman of the Board, Chief Executive Officer, and President of PG&E Corporation, hereby constitutes and appoints LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Chairman of the Board, Chief Executive Officer, and President (principal executive officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2001, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 20th day of February, 2002.

/s/ ROBERT D. GLYNN, JR.

Robert D. Glynn, Jr.

POWER OF ATTORNEY

PETER A. DARBEE, the undersigned, Senior Vice President and Chief Financial Officer of PG&E Corporation, hereby constitutes and appoints LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Senior Vice President and Chief Financial Officer (principal financial officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2001, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 20th day of February, 2002.

/s/ PETER A. DARBEE

Peter A. Darbee

POWER OF ATTORNEY

CHRISTOPHER P. JOHNS, the undersigned, Senior Vice President and Controller of PG&E Corporation, hereby constitutes and appoints LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Senior Vice President and Controller (principal accounting officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2001, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 20th day of February, 2002.

/s/ C HRISTOPHER P. J OHNS

Christopher P. Johns

POWER OF ATTORNEY

Each of the undersigned Directors of Pacific Gas and Electric Company hereby constitutes and appoints LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Form 10-K Annual Report for the year ended December 31, 2001, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 20th day of February, 2002.

/s/ DAVID R. ANDREWS	/s/ DAVID M. LAWRENCE, MD
David R. Andrews	**David M. Lawrence, MD**
/s/ DAVID A. COULTER	/s/ MARY S. METZ
David A. Coulter	**Mary S. Metz**
/s/ C. LEE COX	/s/ CARL E. REICHARDT
C. Lee Cox	**Carl E. Reichardt**
/s/ WILLIAM S. DAVILA	/s/ GORDON R. SMITH
William S. Davila	**Gordon R. Smith**
/s/ ROBERT D. GLYNN, JR.	/s/ BARRY LAWSON WILLIAMS
Robert D. Glynn, Jr.	**Barry Lawson Williams**

POWER OF ATTORNEY

GORDON R. SMITH, the undersigned, President and Chief Executive Officer of Pacific Gas and Electric Company, hereby constitutes and appoints LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as President and Chief Executive Officer (principal executive officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2001, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 20th day of February, 2002.

/s/ GORDON R. SMITH

Gordon R. Smith

POWER OF ATTORNEY

KENT M. HARVEY, the undersigned, Senior Vice President—Chief Financial Officer and Treasurer of Pacific Gas and Electric Company, hereby constitutes and appoints LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Senior Vice President—Chief Financial Officer and Treasurer (principal financial officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2001, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 20th day of February, 2002.

/s/ KENT M. HARVEY

Kent M. Harvey

POWER OF ATTORNEY

DINYAR B. MISTRY, the undersigned, Vice President—Controller of Pacific Gas and Electric Company, hereby constitutes and appoints LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Vice President—Controller (principal accounting officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2001, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 20th day of February, 2002.

/s/ D INYAR B. M ISTRY

Dinyar B. Mistry

End of Filing

Powered By EDGAR Online

© 2005 | EDGAR Online, Inc.