PG&E CORP
Form 10-K/A
March 05, 2002

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K/A
Amendment No. 1 to

(Mark One)
[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2000

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	Stat Incorp
1-12609	PG&E CORPORATION	Cali
1-2348	PACIFIC GAS AND ELECTRIC COMPANY	Cali

Pacific Gas and Electric Company	PG&E Cor
77 Beale Street	One Market,
P.O. Box 770000	Suite
San Francisco, California	San Francisco
(Address of principal executive offices)	(Address of principa
94177	941
(Zip Code)	(Zip
(415) 973-7000	(415) 2
(Registrant's telephone number, including area code)	(Registrant's telephone

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

Title of Each Class	Name
PG&E Corporation	
Common Stock, no par value	New York St
Preferred Stock Purchase Rights	Pacific Exc
Pacific Gas and Electric Company	
First Preferred Stock, cumulative,	American St
par value $25 per share:	Pacific Exc
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,	American St
Series A (liquidation preference $25), issued by PG&E	Pacific Exc

Capital I and guaranteed by Pacific Gas and Electric Company

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 [x] 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 April 9, 2001:

PG&E Corporation Common Stock	$2,505 million

Common Stock outstanding as of April 9, 2001:

PG&E Corporation:	387,137,690 (inc shares held by sub)
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 for the year ended December 31, 2000...	Part I (Item 1), P Part IV (Item 14)
(2) Designated portions of the Joint Proxy Statement relating to the 2001 Annual Meetings of Shareholders...	Part III (Items 10

INTRODUCTORY NOTE

PG&E Corporation has previously disclosed that its subsidiary, PG&E National Energy Group, Inc (PG&E NEG), has used "synthetic leases" in connection with some of its power plant projects and turbine acquisition commitments. Subsequent to the issuance of PG&E Corporation's 1999 and 2000 consolidated financial statements, management determined that the assets and liabilities associated with these leases should have been consolidated. This Amendment No. 1 to PG&E Corporation's and Pacific Gas and Electric Company's joint Annual Report on Form 10-K for the year ended December 31, 2000, contains revised consolidated financial statements for PG&E Corporation for the years ended December 31, 1999 and 2000. To reflect the revisions, this Amendment No. 1 hereby amends:

Part I, Item 1. Business (by correcting the statement of the amount of PG&E Corporation's assets for the year ended December 31, 2000 that appears on page 2 of the original filing)

Part I, Items 2 through 4 - unchanged

Part II, Item 5. Market for Registrant's Common Equity and Related Stockholder Matters (references are to amended 2000 Annual Report to Shareholders)

Part II, Item 6. Selected Financial Data (references are to amended 2000 Annual Report to Shareholders)

Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, (references are to amended 2000 Annual Report to Shareholders)

Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk (references are to amended 2000 Annual Report to Shareholders)

Part II, Item 8. Financial Statements and Supplementary Data (references are to amended 2000 Annual Report to Shareholders)

Part III, Items 10 through 13 - unchanged

Part IV, Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K (amended to file herewith amended Exhibit 13 - portions of the amended 2000 Annual Report to Shareholders, Exhibit 23.1 - Independent Auditors' Consent (Deloitte & Touche LLP), and Exhibit 23.2 - Consent of Arthur Andersen LLP. All other exhibits that were filed with the original filing have not been re-filed with this amendment but instead have been incorporated by reference to the original filing.)

Although the full text of the amended Form 10-K is contained herein, this Amendment No. 1 does not update any other disclosures to reflect developments since the original date of filing.

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PART II

PART III

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
BCAP .... Biennial Cost Allocation Proceeding
bcf .... billion cubic feet
Betz .... Betz Chemical Company
BFM .... block forward market
BRPU .... Biennial Resource Plan Update
BTA .... best technology available
Btu .... British thermal unit
CARE .... California Alternate Rates for Energy
CCAA .... California Clean Air Act
CEC .... California Energy Commission
CEMA .... Catastrophic Event Memorandum Account
Central Coast Board .... Central Coast Regional Water Quality Control Board
CEQA .... California Environmental Quality Act
CERCLA .... Comprehensive Environmental Response, Compensation, and Liability
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
CPA .... California Procurement Adjustment
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
DSM .... demand side management
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
PG&E GTN	PG&E Gas Transmission, Northwest Corporation, formerly known as Pacific Gas Transmission Company
PG&E GTN Expansion	PG&E Gas Transmission, Northwest Corporation's portion of the Pipeline Expansion
Holding Company Act	Public Utility Holding Company Act of 1935
Humboldt	Humboldt Bay Power Plant
HWRC	hazardous waste remediation costs
ICIP	Incremental Cost Incentive Price

GLOSSARY OF TERMS--(Continued)

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
MMcf/d	million cubic feet per day
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 Expansion	the Pacific Gas and Electric Company portion of the Pipeline Expansion
PG&E ET	PG&E Corporation's energy commodities activities, PG&E Energy Trading or PG&E ET
PG&E ES	PG&E Corporation's energy services operations, PG&E Energy Services or PG&E ES
PG&E Gen	PG&E Generating Company, LLC and its affiliates
PG&E GT	PG&E Corporation's gas transmission operations, PG&E Gas Transmission or PG&E GT
PG&E GTT	PG&E Gas Transmission, Texas Corporation
PG&E OSC	PG&E Operating Services Company
Pipeline Expansion	PG&E GT NW/PG&E Pipeline Expansion
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
PVC .... Pacific Venture Capital, LLC
PX .... California Power Exchange
PY .... Program Year
QF .... qualifying facility
RAP .... Revenue Adjustment Proceeding

GLOSSARY OF TERMS--(Continued)

RCRA .... Resource Conservation and Resource 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 .... Scheduled Coordinator Services
SO2 .... sulfur dioxide
SoCal Gas .... Southern California Gas Company
SPE .... special purpose entity
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.

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 in the U.S. Bankruptcy Court for the Northern District of California. 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. 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 2000 Annual Report to Shareholders, which information is incorporated by reference into this report.

The consolidated financial statements of PG&E Corporation incorporated herein include the accounts of PG&E Corporation and its wholly owned and controlled subsidiaries (collectively, PG&E Corporation). The consolidated financial statements of Pacific Gas and Electric Company incorporated herein include the accounts of Pacific Gas and Electric Company and its wholly owned and controlled subsidiaries.

The principal executive offices of PG&E Corporation are 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 Corporation's subsidiary, PG&E National Energy Group, Inc. (NEG), is an integrated energy company with a strategic focus on power generation, new power plant development, natural gas transmission, and wholesale energy marketing and trading in North America. NEG businesses include its power plant development and generation unit, PG&E Generating Company, LLC and its affiliates (collectively, PG&E Gen); its natural gas transmission unit, PG&E Gas Transmission Corporation (PG&E GT); and its wholesale energy and marketing trading unit, PG&E Energy Trading Holdings Corporation, which owns PG&E Energy Trading--Gas Corporation, and PG&E Energy Trading--Power, L.P. (collectively, PG&E Energy Trading or PG&E ET). During 2000, NEG sold its energy services unit, PG&E Energy Services Corporation. Also, during 2000, NEG sold its Texas natural gas and natural gas liquids business carried on through PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. and their subsidiaries (PG&E GTT). For more information about NEG's businesses, see "PG&E National Energy Group, Inc." below.

In December 2000, and in January and February 2001, PG&E Corporation and NEG undertook a corporate restructuring of NEG, known as a "ringfencing" transaction. The ringfencing complied with credit rating agency criteria enabling NEG, PG&E Gas Transmission, Northwest Corporation (PG&E GTN), and PG&E ET to receive or retain their own credit ratings based on their own creditworthiness. The ringfencing involved the creation or use of special purpose entities (SPEs) as intermediate owners between PG&E Corporation and its non-CPUC regulated subsidiaries. These SPEs are: PG&E National Energy Group, LLC which owns 100% of the stock of 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, in March

2001, NEG's organizational documents were modified to include the same structural elements as the SPEs to meet credit rating agency criteria. Ringfencing is intended to reduce further the likelihood that the assets of the ringfenced

companies would be substantively consolidated in a bankruptcy proceeding involving such companies' ultimate parent, and to thereby preserve the value of the "protected" entities as a whole. The SPEs require unanimous approval of their respective boards of directors, including at least one independent director, before they can (a) consolidate or merge with any entity, (b) transfer substantially all of their assets to any entity, or (c) institute or consent to bankruptcy, insolvency, or similar proceedings or actions. The SPEs may not declare or pay dividends unless unanimously approved by the SPE's board of directors and the company meets specified financial requirements.

PG&E Corporation has identified four reportable operating segments. The Utility is one reportable operating segment and the other three are part of NEG (PG&E Gen, PG&E GT, and PG&E ET). Financial information about each reportable operating segment is provided in "Management's Discussion and Analysis" in the 2000 Annual Report to Shareholders and in Note 16 of the "Notes to Consolidated Financial Statements" beginning on page 86 of the 2000 Annual Report to Shareholders, which information is incorporated by reference into this report.

As of December 31, 2000, PG&E Corporation had $36.2 billion in assets. Of this amount, Pacific Gas and Electric Company had $22 billion in assets. PG&E Corporation generated $26.2 billion in operating revenues for 2000. Of this amount, the Utility generated $9.6 billion in operating revenues for 2000. As of December 31, 2000, PG&E Corporation and its subsidiaries and affiliates had 20,850 employees (including 18,393 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 include:

- the reorganization plan that is ultimately adopted by the bankruptcy court;

- the regulatory, judicial, or legislative actions (including future ballot initiatives) that may be taken to meet future power needs, mitigate the higher wholesale power prices, provide refunds for prior power costs, or address the Utility's financial condition;

- the extent to which the Utility's undercollected wholesale power purchase costs may be collected from customers;

- 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;

- future market prices for electricity and future fuel prices which, in part, are influenced by future weather conditions, the availability of hydroelectric power, and the development of competitive markets;

- the method and timing of valuation of the Utility's hydroelectric generation assets;
- future operating performance at the Diablo Canyon Nuclear Power Plant (Diablo Canyon) and the future ratemaking applicable to Diablo Canyon;
- legislative or regulatory changes, including the pace and extent of the ongoing restructuring of the electric and natural gas industries across the United States;
- future sales levels and economic conditions;
- the extent to which NEG's current or planned generation development projects are completed and the pace and cost of such completion;
- generating capacity expansion and retirements by others;
- the outcome of the Utility's various regulatory proceedings;
- fluctuations in commodity gas, natural gas liquids, and electric prices and the ability to successfully manage such price fluctuations;
- the effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant; 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 regulation, utilities were provided the opportunity to earn a fair return on their invested capital in exchange for a commitment to serve all customers within a designated service territory. 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 framework 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). 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). For those customers who have not chosen an alternative generation provider, investor-owned utilities, such as Pacific Gas and Electric Company, 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 an alternative generation provider.

Beginning in June 2000, the wholesale price of electric power in California has steadily increased, reflecting a dysfunctional wholesale power market. Under AB 1890, the Utility's electric rates were frozen at levels insufficient to recover the Utility's cost of purchasing power for its customers. Further, the Utility was required to buy all the power it needed to serve its customers from the PX. The combination of these factors created a financial crisis for the Utility and its parent, PG&E Corporation. The Utility's undercollected power purchase costs grew to $6.6 billion at December 31, 2000. As the Utility's creditworthiness deteriorated, the Utility was unable to continue financing these purchases. Federal and state legislators and regulators have recognized that the wholesale power market is seriously flawed and have been seeking solutions to the California electricity crisis. On January 19, 2001, the California Legislature passed and the Governor signed Senate Bill 7X which authorized the California Department of Water Resources (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 1 (AB 1X) which was passed by the California Legislature during a special session to take effect immediately as an urgency statute. AB 1X authorizes the DWR to purchase power and sell that power directly to the utilities' retail end use customers. For more information about California electric industry restructuring, see "Utility Operations--Electric Utility Operations--California Electric Industry Restructuring" below.

As of December 31, 2000, 24 other states had enacted electric industry restructuring legislation or issued comprehensive regulatory orders, including Texas, Illinois, Pennsylvania, New Jersey, Massachusetts, Rhode Island, New York, and Connecticut.

In October 1999, the CPUC issued a decision outlining how the CPUC, in cooperation with other regulatory agencies and the California Legislature, plans to address the issues surrounding distributed generation, electric distribution competition, and the role of the utility distribution companies (such as Pacific Gas and Electric Company) in the competitive retail electricity market. Distributed generation enables siting of electric generation technologies in proximity to electric load (load is a measure of electric power consumed over time). The CPUC decision opened a new rulemaking proceeding to examine various issues concerning distributed generation, including interconnection issues, who can own and operate distributed generation, environmental impacts, the role of utility distribution companies, and the rate design and cost allocation issues associated with the deployment of distributed generation facilities. In July 2000, the CPUC's Division of Strategic Planning and the CPUC's Energy Division issued a report on electric retail markets and distribution services as required by the October 1999 decision. The report proposed that if the CPUC chooses to consider expanding or consolidating competition in the electric industry, the CPUC should (a) separately identify utility services and establish cost-based rates for these services, (b) consider allowing providers of billing and metering services to market directly to customers, (c) consider allowing multiple providers of default service, and (d) investigate whether to allow competition in certain aspects of distribution services that utilities currently perform. There is currently no active proceeding on electric distribution and the role of utility distribution companies.

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.

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). 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 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 to meet the Utility's service obligations, shall be given first priority by the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company. 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, inter-company 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 since deregulation of the electric industry commenced, 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 (including penalties), 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. As described above, on April 6, 2001, the Utility filed a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code. PG&E Corporation and the Utility believe that to the extent the CPUC seeks to investigate past conduct for compliance purposes, the investigation is automatically stayed by the bankruptcy filing. Neither the Utility nor PG&E Corporation can predict what the outcome of the investigation will be or whether the outcome will have a material adverse effect on their results of operation or financial condition.

Regulation of Pacific Gas and Electric Company

Federal Regulation

The FERC regulates electric transmission rates and access, operation of the California ISO and the California PX, uniform systems of accounts, and contracts involving the wholesale sale of power. The ISO has responsibility for meeting applicable reliability criteria and assuring the maintenance of adequate reserves. The PX, which has now suspended operations, had the responsibility of conducting an open, efficient auction for matching energy bids to supply with demand bids to purchase energy. Both these entities were subject to FERC regulation of tariffs and conditions of service. In addition, the FERC has jurisdiction over the Utility's electric transmission revenue requirements and rates. 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 an 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 nuclear generating unit at Humboldt Bay Power Plant (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 regulate the following utility functions within California: electric distribution service, gas distribution service, and gas transmission service. The CPUC regulates Pacific Gas and Electric Company's rates and conditions of service, sales of securities, dispositions of utility property, rates of return, rates of depreciation, and long-term resource procurement. 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 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 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, United States 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 10 hydroelectric projects and one transmission line project undergoing FERC license renewal.

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 NEG through PG&E Gen, its subsidiaries, and affiliates, and of power contractually controlled by them is subject to FERC jurisdiction under the Federal Power Act. Various 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 were the FERC to conclude that the rates charged are no longer just and reasonable. Such a conclusion could be reached were the FERC to conclude, for example, that a NEG subsidiary or affiliate has excess market power. The FERC also regulates the rates, terms, and conditions for electric transmission in interstate commerce. Tariffs established under FERC regulation provide NEG with the necessary access to transmission lines.

The FERC also licenses all of NEG's hydroelectric and pumped storage projects. These licenses, which are issued for 30 to 50 years, will expire at different times between 2001 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.

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.

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, and application has been made to construct the U.S. segment of the North Baja Pipeline. 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, 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 Department of Energy 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, 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 producers. As a result, power sales agreements, which NEG affiliates enter into with such utilities, are potentially subject to review by the public utility commissions, through the commissions' power to review, for example, the process by which the utilities have entered into these agreements. 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 commissions have 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 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 which can impact customers' ability to import gas for transport over NEG pipelines.

Other regulatory matters are described throughout this report. For a discussion of environmental regulations to which PG&E Corporation and it 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, which include non-fuel-related operating and maintenance costs, depreciation, taxes, and a return on invested capital, currently are authorized by the CPUC in General Rate Case (GRC) proceedings. During the GRC, which occurs every three years, the CPUC examines the Utility's costs and operations to determine the amount of base revenue requirement the Utility is authorized to collect from customers through base revenues. The revenue requirement is forecasted on the basis of a specified test year. (The return component of the Utility's revenue requirement is computed using the overall cost of capital authorized in other proceedings.) 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. Since base revenues are determined for a three-year period by GRCs, 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. The 1999 and 2002 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 ROR was 10.6%. The adopted ROR 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 requests 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 is expected in the second quarter of 2001.

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 and Gas Distribution Performance-Based Ratemaking (PBR). In June 2000, the CPUC granted the Utility's request to withdraw its PBR application filed in November 1998. The Utility had requested the withdrawal in accordance with the 1999 GRC decision issued in February 2000, which required a 2002 GRC before a PBR revenue/rate indexing mechanism could be implemented. In closing the PBR proceeding, the CPUC ordered the Utility to file a new PBR application by September 2000.

In September 2000, the Utility filed an application with the CPUC to establish (1) performance standards and associated financial rewards and penalties for electric and gas distribution service, (2) a revenue-sharing mechanism for new categories of non-tariffed products and services (NTP&S)

offered by the Utility and (3) ratemaking for proceeds from sales or transfers of certain non-generation related land. The performance standards would cover a period of five years beginning January 1, 2001. The total maximum annual reward or penalty is $54 million per year, consisting of $52 million for electric distribution and $2 million for gas distribution. The revenue-sharing mechanism proposes to share net positive after-tax revenues from new categories of NTP&S equally between ratepayers and shareholders. Finally, the Utility requested that the CPUC establish basic rules about the allocation of gains and losses from the Utility's non-generation-related land sales. In November 2000, the CPUC suspended the schedule in the PBR proceeding until further order.

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. The rate freeze ends 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. In 1997, the Utility, through a special purpose entity, refinanced the expected 10% rate reduction with $2.9 billion of rate reduction bonds. At December 31, 2000, $2 billion of bonds remained outstanding. If the transition period ends 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.

The Utility has advised the CPUC that it had recovered all of its transition costs during August 2000 (and possibly as early as May 2000, depending on the final valuation of the Utility's hydroelectric generating assets and when the rate freeze is determined to have ended). The Utility 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. The Utility believes that after the rate freeze is determined to have ended, the Utility is entitled to recover from ratepayers the costs it incurred to purchase power on behalf of retail customers. At December 31, 2000, the balance of the Utility's undercollected power purchase costs was $6.6 billion. PG&E Corporation and the Utility recognized a fourth quarter charge to earnings of $6.9 billion ($4.1 billion after tax) to reflect the fact that the Utility could no longer conclude that its generation-related regulatory assets and undercollected purchased power costs were probable of recovery from ratepayers.

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 an 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 the Utility's past and ongoing wholesale power purchase costs. The Utility requested that its proposed RSP rates and tariffs be adopted by January 1, 2001, on an interim basis, subject to refund, and that the CPUC approve the application by no later than March 31, 2001.

The Utility also proposed to defer receiving a portion of its share of profits from its retained generation facilities, primarily from the Diablo Canyon nuclear power plant and its hydroelectric plants, until a later time during the five-year period and allow those funds instead to be used to offset uncollected power purchase costs. The Utility proposed that for the next two years (after which the Utility expects the current supply shortage will be less critical), the Utility retain its generation facilities and sell the output of these facilities directly to its retail distribution customers on an incentive ratemaking basis to lower the costs of procured power for such customers.

On January 4, 2001, the CPUC issued an emergency interim decision denying the Utility's emergency request for a rate increase. Instead of the requested relief, the CPUC approved a 90-day temporary rate increase of 1 cent per kilowatt hour (kWh), subject to refund and adjustment. This rate increase, which raises approximately $70 million per month, is grossly insufficient for the Utility to pay its ongoing procurement bills or to make further financing of these costs possible.

On March 27, 2001, the CPUC issued a decision making the 1 cent per kWh surcharge permanent and authorizing the Utility to add an average 3 cent per kWh surcharge to current rates. Although the increase is authorized immediately, the 3 cent per kWh surcharge will not be collected in rates until the CPUC establishes an appropriate rate design for the surcharge, which is not expected to be adopted until May 2001, at the earliest. The revenue generated by the rate increase is to be used only for electric power procurement costs that are incurred after March 27, 2001. The rate increase is subject to refund (1) if not used to

pay for such power purchases, (2) to the extent that generators and sellers of power make refunds for overcollections, or (3) to the extent any administrative body or court denies the refunds of overcollections in a proceeding where recovery has been hampered by a lack of cooperation from the Utility. In addition, the CPUC ordered that the 3 cent per kWh surcharge be added to the rate paid to the DWR as adopted by the CPUC in a companion decision discussed below.

Also 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 equal to the applicable generation-related retail rate per kWh established for each utility as in effect on January 5, 2001, for each kWh the DWR sells to the customers of each utility. The CPUC determined that the generation-related component of retail rates should be equal to the total bundled electric rate (including the 1 cent per kWh interim surcharge adopted by the CPUC on January 5, 2001) less the following non-generation-related rates or charges: transmission, distribution, public purpose programs, nuclear decommissioning, and the fixed transition amount. The CPUC determined that the Utility's company-wide average generation-related rate component is 6.471 cents per kWh and that this is the amount that should be paid to the DWR for each kWh delivered by the DWR to the Utility's retail customers after February 1, 2001, until specific rates are calculated. The CPUC ordered the utilities to pay the DWR within 45 days after the DWR supplies power to their retail customers, subject to penalties for each day that payment is late. The amount of power supplied to retail end-use customers after March 27, 2001, for which the DWR is entitled to be paid would be based on the product of the number of kWh that the DWR provided 45 days earlier and the Utility's company-wide average generation-related rate of 6.471 cents per kWh, and the additional 3 cent per kWh surcharge described above.

The CPUC also ordered that the utilities immediately pay the sums owed to the DWR for power sold by the DWR from January 18, 2001 through January 31, 2001, under California Senate Bill 7X. Based on an estimated number of kWh sold by the DWR, the Utility paid approximately $30 million to the DWR at the rate of 5.471 cents per kWh as adopted by the CPUC.

As the DWR has not advised the CPUC of its revenue requirement for the

DWR's power purchases, it is unclear how much of the 3 cent surcharge will be needed by the DWR and how much, if any, may be used by the Utility to recover its procurement costs incurred after March 27, 2001.

General Rate Case. In February 2000, the CPUC issued a decision in the Utility's 1999 GRC for the period 1999-2001. 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. In March 2000, two intervenors filed applications for rehearing of the decision, alleging that the CPUC committed legal errors by approving funding in certain areas that were not adequately supported by record evidence. In April 2000, the Utility filed its response to these applications for rehearing, defending the GRC decision against the allegations of error. A CPUC decision on the applications for rehearing is pending.

The 1999 GRC decision also ordered that the Utility file a 2002 GRC. In July 2000, the CPUC issued a decision requiring the Utility to file a Notice of Intent (NOI) with the CPUC by May 1, 2001. The CPUC decision affirms that rates would still become effective on January 1, 2002, although the CPUC decision may not be rendered until late 2002. In January 2001, the Utility filed a petition with the CPUC requesting that the May 1, 2001 deadline for filing the NOI be suspended, asserting that many assumptions that would have to be made in order to forecast year 2002 costs would very likely need to be changed based on how the wholesale electricity price and natural gas supply crises are resolved. The Utility requested that it be allowed to file an alternative to the schedule, or to the GRC itself, by May 1, 2001. The CPUC has not acted on the Utility's January 2001 petition. On March 27, 2001, the CPUC extended the NOI filing date by the number of days from March 5, 2001 to 30 days after the CPUC renders a decision on the petition. The extension will become effective only if the CPUC denies the petition. If the CPUC grants the petition, the Utility would be allowed to file an alternative schedule or an alternative to the GRC and the CPUC would subsequently decide how to proceed with the case.

2001 Attrition Rate Adjustment Request. In July 2000, the Utility filed an attrition rate adjustment application with the CPUC to increase its 2001 electric distribution revenues by $189 million, effective January 1, 2001, to reflect inflation and the growth in capital investments necessary to serve customers. The Utility did not request an increase in gas distribution revenues. On December 21, 2000, the CPUC issued an interim order finding that a decision on the merits of this application cannot be rendered by January 1, 2001, and determining that if attrition relief is eventually granted, that relief will be effective as of January 1, 2001. Hearings are scheduled to begin in June 2001, and a CPUC decision is expected by January 2002.

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. Due to the high wholesale power costs at which the Utility has been required to purchase power for its distribution customers since June 2000, revenues from frozen rates have been grossly insufficient to recover the Utility's operating costs, resulting in a TRA under-collection of $6.6 billion at December 31, 2000. On January 4, 2001, the CPUC issued a decision in the Utility's 1999 RAP approving the transfer of $967 million of residual revenue in the TRA to the TCBA for the period from June 1, 1998 through June 30, 1999, and adopted a PX credit adder of .007 cents per kWh for utility customers that elect direct access to offset the energy costs included in the bundled rate. The Utility will file its application for its next RAP to address revenues and costs recorded in the TRA from July 1, 1999 through at least April 30, 2001, on or before June 1, 2001. One of the CPUC's March 27, 2001, decisions retroactively changes the TRA and TCBA accounting mechanisms. (See "Electric Utility Operations--Electric Industry Restructuring--New California Legislation," below.)

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. Transition costs will receive a limited "reasonableness" review. On January 4, 2001, the CPUC issued a decision in the Utility's 1999 ATCP finding that $2.6 billion recorded in the TCBA from July 1, 1998 through June 30, 1999 are eligible for recovery as transition costs. 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 expected to be issued in the second quarter of 2001. 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.

As required by the CPUC, in August 2000, the Utility made a filing with the CPUC that estimated the market value of the Utility's remaining hydroelectric generating assets at $2.8 billion (based on a negotiated value used in a proposed settlement discussed below under "Electric Resources--Hydroelectric Generation Assets.") The Utility credited its TCBA by $2.1 billion, the amount of the estimated value over the assets' book value. At the same time, the Utility made a corresponding debit entry of the same amount in the newly established Generation Asset Balancing Account (GABA) to prevent an immediate charge to earnings that would have otherwise resulted from the credit to the TCBA. The filing will become effective after appropriate review by the CPUC's Energy Division and the TCBA entries are subject to review in the 2001 ATCP to be filed September 1, 2001. The Utility believes that with the credit to the TCBA, the Utility has recovered all of its transition costs as of early August 2000. If the final value of the hydroelectric assets is higher than the estimate, the Utility believes its transition costs would have been recovered as of an earlier date, possibly as early as May 2000. However, in a decision issued on March 27, 2001, the CPUC has stated that with the retroactive accounting changes adopted in the decision, the conditions for meeting the rate freeze have not been met. See "Electric Utility Operations--Electric Industry Restructuring--New California Legislation," below.

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 CPUC's Officer of Ratepayer Advocates (ORA), and The Utility Reform Network (TURN), challenging the evidentiary support for the costs, among other concerns. This matter is pending.

Revenues from Must-Run Contracts. The ISO has designated certain units at electric generation facilities as necessary to remain available 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. The owners of must-run units choose among two different forms of must-run contract, both of which cover operating costs. One form provides payments of a percentage of the unit's fixed cost revenue requirement and does not limit market participation. The other form provides 100% fixed cost recovery but allows only very restricted market participation. The Utility's two remaining fossil-fueled power plants (Hunters Point and Humboldt Bay), three of its hydroelectric generation facilities, and a combustion turbine located at a substation in San Jose, California, are under must-run contracts. The form of must-run contract chosen for all of these facilities (except Hunters Point and the combustion turbine) is the one that does not limit market participation. The Utility currently receives approximately $91 million per year as payments under these must-run contracts, plus fuel costs. In addition, the Utility has the opportunity to earn market revenues for all of these plants except Hunters Point and the combustion turbine, when the ISO has not dispatched the plant.

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, 2000, the Utility has recorded approximately $33 million of these scheduling coordinator costs in the TRBA. (The Utility has also disputed approximately $26 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 2001. 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 the Utility 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, the 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. Since April 1998, electric transmission revenues have been authorized by the FERC, including various rates to recover transmission costs from the Utility's former bundled retail transmission customers. The FERC has not yet acted upon a settlement filed by the Utility that, if approved, would allow the Utility to recover $345 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 by the end of 2001. The Utility has accrued $24 million for potential refunds related to the period ended May 31, 1999. In April 2000, the FERC approved a settlement that permits the Utility to recover $264 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 November 2000, the FERC accepted, subject to refund, the Utility's proposal to collect $397 million in electric transmission rates beginning on May 6, 2001.

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 after the rate freeze 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 undercollected 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. 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 1999-2001. 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 2002 GRC, see above under "Electric Ratemaking.")

The Core Fixed Cost Account (CFCA) is the regulatory balancing account that matches gas distribution and storage authorized revenue to the actual revenue collected from core customers. During May 2000, the Utility refunded approximately $320 million to core gas customers to reduce an over-collection in the CFCA. Since the volumes of gas delivered to core customers during the 1998 and 1999 winter seasons were higher than the forecasted volumes used to set the rates, an over-collection resulted. Beginning in December 2000, storage activity is recorded in a new procurement balancing account, Core Firm Storage Account, instead of in the CFCA, and are included in monthly core procurement rates.

Gas Procurement Costs. The Utility procures gas for more than 90 percent 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 of 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 co-generation 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. If the settlement is adopted, there would be a decrease in the base revenue requirement of approximately $113 million, subject to adjustment for the most recent balancing account balances and CPUC decisions in place when the CPUC acts on the proposed settlement. A decision is expected in the third quarter of 2001.

Public Purpose Programs

Under state law, the Utility is authorized to collect not less than $198 million in a separate nonbypassable charge included in frozen electric 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 programs at not less than $14 million per year. 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 $31 million per year.

Under the oversight of the CPUC, the Utility administers both the cost-effective energy efficiency and low-income energy efficiency programs. These two programs are reviewed annually in the Annual Earnings Assessment Proceeding (AEAP). In March 1999, the CPUC determined that these programs should continue to be administered by investor-owned utilities, subject to CPUC oversight, through 2001. Effective January 1, 2000, Section 327 of the California Public Utilities Code requires utilities to continue to administer low-income energy efficiency programs. The California Energy Resources Conservation and Development Commission (also called the California Energy Commission (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.

In October 2000, the California Legislature passed and the Governor signed legislation extending the existing surcharge on electricity to fund public purpose energy efficiency, renewable energy, and research development and demonstration programs for another 10 years, beginning January 1, 2002.

The AEAP determines shareholder incentives to be earned for the Utility's demand side management (DSM) programs. The 1999 AEAP determines shareholder incentives to be earned for the Utility's pre-1998 DSM activities and 1998 and later energy efficiency programs. The Utility was authorized in 2000 to collect

$15.67 million for pre-1998 DSM earnings, $0.11 million for Program Year (PY) 1998 Low-Income Energy Efficiency (LIEE) earnings, and $10.45 million for PY 1998 non-LIEE earnings. After consolidating the adjusted incentive payment installments from prior years, the net revenue change in 2000 from shareholder incentives should be an electric increase of approximately $3.4 million and a gas decrease of approximately $1.5 million. In May 2000, the Utility filed its 2000 AEAP application seeking to recover approximately $53 million of shareholder incentives for attainment of milestones for PY 1999 energy efficiency programs, and for achieving savings for PY 1998 and 1999 LIEE programs and for DSM accomplishments related to pre-1998 program commitments. In October 2000, the CPUC postponed the proceedings until further notice.

Electric Utility Operations

Electric Industry Restructuring

The goal of California electric industry restructuring (AB 1890) was to open up the electric generation function of traditional utilities to competition to give electric customers of investor-owned utilities (such as Pacific Gas and Electric Company) the choice of continuing to purchase electric power from investor-owned utilities or purchasing electric power from alternative providers (including independent power generators and retail electricity providers such as marketers, brokers, and aggregators). Purchasing electric power from an alternative generation provider is called "direct access." Beginning March 31, 1998, customers were permitted to choose 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. During the transition period, the California investor-owned utilities were required to sell into the PX all of their generated electric power. "Must-take" generation resources, such as nuclear generation from Diablo Canyon, electric power generated by QFs and electricity that the Utility is required to purchase under existing contractual commitments, were also required to be scheduled through the PX. These "must take" resources were bid into the PX at $0 per megawatt-hour (MWh) to ensure that these resources are used to meet demand. During the transition period, the California investor-owned utilities also were required to buy power on behalf of their retail customers through the PX. Following the divestiture of much of their power generation facilities in connection with electric industry restructuring, the majority of the power purchased through the PX was supplied by third party generators. The CPUC did not permit the utilities to buy power directly from third parties through bilateral agreements until August 2000.

California Power Crisis. California has endured a power crisis as demand for power far outstripped supply. Since June 2000, wholesale power prices in California have steadily increased to an average cost of 18.16 cents per kWh for the seven month period of June 2000 through December 2000, as compared to an average cost of 4.23 cents per kWh for the same period in 1999. During 2000, the Utility collected only approximately 5.4 cents per kWh through frozen rates for the recovery of its wholesale power costs. Many factors have contributed to the high wholesale power prices, including:

- Economic and population growth in California.

- A lack of new power supplies to meet the growing demand.

- A substantial increase in natural gas prices. Since many power plants serving California are natural gas fired, the natural gas prices paid by generators in producing electricity are reflected in the price of power charged by the generators.

- Limited availability of hydroelectric power due to dryer than usual conditions.

- Uncoordinated power plant outages due to scheduled maintenance or unplanned outages.

- Dysfunctional power markets that produced unjust and unreasonable price levels.

- The tendency of frozen retail rates to eliminate the incentive for customers to conserve energy and reduce demand.

- Delays in regulatory approvals to permit the California investor-owned utilities to enter into long-term power purchase contracts as a hedge against price fluctuations. After permission was given in August 2000, there have been further delays in regulatory approvals of reasonableness standards for entering into bilateral contracts.

FERC Order. On December 15, 2000, the FERC issued an order adopting remedies for what the FERC characterized as the seriously flawed electric power markets in California. Among other matters, the FERC:

- Eliminated, effective December 15, 2000, the requirement that the California investor-owned utilities sell all of their generation into and buy all of their energy needs from the PX, which results in over reliance on spot market (i.e., real-time) purchases. The order encourages the utilities to meet their purchase power needs through bilateral long-term contracts of two years or more and to adopt a balanced portfolio of contracts to mitigate cost exposure. To encourage the execution of bilateral contracts, the order requires the PX's rate schedules to terminate effective at the close of business on April 30, 2001.

- Adopted a price benchmark at $74 per MWh for assessing prices of five-year energy supply contracts to be used by the FERC in assessing any complaints regarding justness and reasonableness of pricing long-term contracts.

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- Permitted penalties to be imposed on market participants who do not schedule at least 95% of their load in advance of the ISO's real-time market (through self-scheduling, bilateral contracts, or the PX markets), to reduce the reliance on the ISO's real-time market to meet supply. A penalty charge will be assessed when more than 5% of a market participant's load is scheduled into the ISO's real-time market. Penalties are to be disbursed to other market participants who schedule their load properly. The FERC order does not contain provisions for penalties to be imposed on generators who do not schedule in advance.

- Established an interim $150 per MWh "soft cap" modification of the single price auction so that bids above $150 MWh will not set the market clearing prices paid to all bidders at or below $150 per MWh. Bids above the $150 MWh level will trigger certain weekly reporting requirements and FERC monitoring. These price provisions will be in effect until April 30, 2001.

. Deferred the consideration of retroactive refund issues linked to protective orders associated with the volatile prices experienced in California this past summer. Although the period for potential refund liability continues until December 31, 2002, with respect to specific transactions, refund potential on a transaction will close after 60 days unless the FERC has issued written notification to the seller that its transaction is still under review.

PG&E Corporation and the Utility believe the actions outlined in the order will not provide a complete solution that ensures reliability of the state's electric supply and relief from future price increases, particularly since the FERC order fails to require sellers to enter into forward contracts at reasonable prices, and fails to provide an effective price cap. In addition, the FERC order does not address issues associated with retroactive refund and retroactive remedial authority issues. The Utility has filed a request for rehearing of the FERC's order to the extent that it does not provide effective mitigation of prices. In March 2001, the FERC ordered refunds of $68.7 million for January 2001 and subsequently ordered refunds of $55 million for February 2001 and indicated it would continue to review December 2000 wholesale prices. The generators have appealed the decision, and will supply cost justification. Any refunds will be offset against amounts owed the generators.

The California Independent System Operator and the California Power Exchange. The PX and the ISO, both California public benefit non-profit corporations, began operating on March 31, 1998, as provided for under AB 1890. The FERC has jurisdiction over both the ISO and the PX. Pursuant to the FERC order of December 15, 2000, the ISO Board of Governors, which included representatives of market participants, was replaced with a non-stakeholder board who are independent of market participants.

The ISO operates and controls most of the state's electric transmission facilities (which continue to be owned and maintained by the California utilities) and provides comparable open access to electric transmission service. The ISO accepts balanced schedules for supply and load from scheduling coordinators, including the PX and the Utility, and market participants and manages the availability of electric transmission on a statewide basis for these transactions. The ISO also purchases necessary generation and ancillary services on a real-time basis to maintain grid reliability. The ISO is required to ensure reliable transmission services consistent with planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council. Oversight of utility distribution systems remains with the CPUC.

Until January 31, 2001, 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 markets: the day-ahead market where market participants purchase power for their customers' needs on the following day and the day-of-or hour-ahead market where market participants purchase power needed to serve their customers on the same day. The PX set a market-clearing price for electricity by matching all demand bids (the amount of energy that an eligible customer is willing to purchase and the maximum price that the customer is willing to pay) with supply bids (the price at which a seller is prepared to sell energy) ranked from lowest to highest. The highest-accepted generation supply bid used to serve load set the PX market-clearing price for electricity. The market-clearing price then became the single cost for electricity throughout California for that energy delivery hour. Due to 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. On January 31, 2001, the PX suspended its day-of and day-ahead markets in response to the FERC's order directing the PX to comply with the terms of its December 15, 2000 order and implement a $150 per MWh "soft" price cap. The FERC ordered the PX to recalculate all PX transactions since December 15, 2000. The PX subsequently filed for bankruptcy protection.

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In May 1999, the PX obtained FERC approval to operate the block forward market (BFM), an exchange that matches bids to buy power with offers to sell power more than one day in advance of the contracted delivery date. In July 1999, the Utility obtained CPUC authority to participate in the BFM for contracts that called for delivery by October 31, 2000 and subject to a volume limit. In March 2000, the CPUC raised the volume limit to permit the Utility to cover its "net open position" (the amount of power to meet the Utility's customers' needs that can not be met with Utility-owned generation or power under contract to the Utility) and affirmed that all PX purchases made during the transition period are deemed reasonable. The CPUC also expanded the Utility's authority to participate in the BFM through the end of the transition period. Participation in the BFM lessened after the FERC's December 15, 2000 order, discussed above. The PX sought to liquidate the Utility's BFM contracts for the purchase of power. On January 25, 2001, a California Superior Court judge granted the Utility's application for a temporary restraining order, which thereby restrained and enjoined the PX from liquidating the Utility's contracts, pending a hearing on a preliminary injunction on February 5, 2001. Immediately before the hearing, California Governor Gray Davis, acting under California's Emergency Services Act, commandeered the 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 the monies that the Utility owes to the PX from any proceeds realized from those contracts. The Utility has filed a claim with the California Victim Compensation and Government Claims Board which will be heard with other claims filed by the PX.

New California Legislation. Some generation providers refused to sell power into the California markets based on their concern as to the credit quality of the California investor-owned utilities whose rates were still frozen. The Secretary of the U.S. Department of Energy (DOE) ordered such providers to continue selling into the California markets on request by the ISO. On January 18, 2001, the California Assembly passed Senate Bill 7X that appropriated $400 million and authorized the DWR to use such funds to purchase power at no more than 5.5 cents per kWh (far less than the current wholesale market rates in early 2001) and then resell it to the Utility at cost to enable the Utility to continue to serve its customers. The DWR was authorized to purchase power through January 31, 2001. On February 1, 2001, the California Governor signed Assembly Bill No. 1 (AB 1X) which was passed by the California Legislature during a special session to take effect immediately as an urgency statute. AB 1X authorizes the DWR to enter into contracts for the purchase of electric power for such periods and at such prices as the DWR deems appropriate consistent with the objectives of AB 1X to have an overall portfolio of contracts resulting in reliable service at the least cost. AB 1X prohibits the DWR from entering into any contract after January 1, 2003. AB 1X requires 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 provides that the DWR will retain title to the power it purchases and that payment for any sale of power by the DWR is a direct obligation of retail end use customers to the DWR. The DWR may contract with the electric utilities for the electric utilities to transmit and distribute the power purchased and sold by the DWR and to provide billing, collection, and other related services, as agent of the DWR, on terms that reasonably compensate the utilities. AB 1X does not authorize the DWR to take ownership of transmission, generation, or distribution assets of any electric utility. AB 1X states it shall not be construed (1) to reduce or modify any electrical corporation's obligation to serve, or (2) to obligate the DWR for any procurement cost obligations of the utilities that existed before January 31, 2001.

AB 1X authorizes the CPUC to set rates to cover revenue requirements of DWR's power purchasing program, 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.

On March 27, 2001, the CPUC issued a decision in which it noted that although the DWR has assumed responsibility to purchase some of the utilities' power requirements, it has not committed to purchase all of the utilities' net open position, i.e., the power needs of the retail electric customers that cannot be met by utility-owned generation or power under contract to the utilities. To the extent the DWR does not buy enough power to cover the Utility's net open position, the ISO purchases emergency power on the high-priced spot market to meet system reliability requirements and the net open position. The ISO may attempt to charge the Utility a proportionate share of the ISO's purchases. The Utility believes that under the current circumstances and applicable tariffs it is not responsible for such ISO charges.

In addition, on April 3, 2001, the CPUC adopted a method to calculate the California Procurement Adjustment, as described in Public Utilities Code Section 360.5 (added by Assembly Bill 1X). Section 360.5 requires the CPUC to determine (1) the portion of each electric utility's electric retail rate effective on January 5, 2001, the "California Procurement Adjustment" or CPA, that is equal to the difference between the generation-related component of the utility's retail rate in effect on January 5, 2001, and the sum of the costs of the utility's own generation, QF contracts, existing bilateral contracts (i.e., entered into before February 1, 2001), and ancillary services, and (2) the amount of the CPA that is allocable to the power sold by the DWR. The CPUC decided that the CPA should be a set rate calculated by determining each utility's generation-

related revenues (for the Utility the CPUC has proposed that this be equal to 6.471 cents per kWh multiplied by total kWh sales by the Utility to the Utility's retail customers), then subtracting each utility's statutorily authorized generation-related costs, and dividing the result by each utility's total kWh sales. Each utility's CPA rate will be used to determine the amount of bonds the DWR may issue.

Using the CPUC's methodology, but substituting the CPUC's cost assumptions with actual expected costs and including costs the CPUC has refused to recognize, the Utility's calculations show that the CPA for the 11-month period February through December 2001 would be negative by $2.2 billion, (i.e., there would be no CPA available to the DWR) assuming the DWR purchases 84 percent of the Utility's net open position. If AB 1X were amended to also include in the CPA all the incremental revenue from the 3 cent per kWh increase discussed above (approximately $2.3 billion for 11 months), then the amount available to the DWR for the CPA for the comparable 11-month period, assuming the Utility were allowed to recover its costs first, would be approximately $100 million. The Utility believes the method adopted by the CPUC is unlawful and inconsistent with Section 360.5 because, among other reasons, it establishes a set rate that does not reflect actual residual revenues, overstates the CPA by excluding and/or understating authorized costs, and to the extent it is dedicated to the DWR does not allow the Utility to recover its own revenue requirements and costs of service. The Utility has filed an application for rehearing of the decision.

Recovery of Transition Costs, Wholesale Power Purchase Costs, and End of Rate Freeze. Based on the premise that market-based revenues would not be sufficient to recover the utilities' uneconomic generation costs, AB 1890 provides the investor-owned utilities the opportunity to recover their transition costs during a transition period ending the earlier of December 31, 2001, or when the particular utility has recovered its transition costs. Some transition costs may 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 sunk costs, such as costs related to plant removal, (2) costs associated with long-term contracts to purchase power at above-market prices from QFs and other power suppliers, and (3) generation-related regulatory assets and obligations. (In general, regulatory assets are expenses deferred in the current or prior periods to be included in rates in subsequent periods.) The Utility tracks the recovery of its transition costs in its TCBA.

Transition costs may be recovered only through the competition transition charge (CTC) (the amount of revenues remaining after paying authorized operating costs), the excess of market value of generating assets over book value, and retained generation revenues. Due to the high wholesale power prices the Utility has been required to pay to purchase power for its customers, revenues from frozen rates since June 2000 have been insufficient to provide any CTC revenues.

Under current CPUC decisions, if undercollected power purchase costs recorded in the TRA are not recovered through frozen rates by the end of the transition period, they cannot be recovered or offset against over-collections of transition costs. The Utility has filed a lawsuit in federal district court against the CPUC challenging these decisions. See "Item 3--Legal Proceedings," below.

Under AB 1890, when the Utility has recovered its eligible transition costs, the conditions for terminating the rate freeze and ending the transition period will have been satisfied. At August 31, 2000, consistent with transition period accounting mechanisms adopted by the CPUC, the Utility credited its TCBA by $2.1 billion, the amount by which a negotiated $2.8 billion hydroelectric generation asset valuation exceeded the aggregate book value of such assets. Based on this credit, the Utility believes it recovered its eligible transition costs during August 2000. At August 31, 2000, there was a balance of approximately $2.2 billion of undercollected wholesale power costs recorded in the TRA. If the final valuation for the hydroelectric assets is greater than $2.8 billion, as the Utility expects, the Utility believes it will have recovered its transition costs possibly as early as May 2000. The undercollected TRA balance as of the end of the earlier determined transition period will be less than the $2.2 billion August 31, 2000 balance and could be zero depending on the ultimate valuation of the hydroelectric assets and when the transition period actually ends. Under current CPUC decisions and AB 1890, the Utility's customers are responsible for wholesale power purchase costs after the Utility has recovered its transition costs.

In one of its March 27, 2001 decisions, the CPUC adopted TURN's proposal to transfer on a monthly basis the balance in each utility's TRA to the utility's TCBA. The accounting changes are retroactive to January 1, 1998. The Utility believes the CPUC is retroactively transforming the undercollected power purchase costs in the TRA into transition costs in the TCBA. However, the CPUC characterized the accounting changes as merely reducing the prior revenues recorded in the TCBA, thereby affecting only the amount of transition cost recovery achieved to date. The CPUC also ordered that the utilities restate and record their generation memorandum accounts balances to the TRA on a monthly basis before any transfer of generation revenues to the TCBA. The CPUC found that based on the accounting changes, the conditions for meeting the end of the rate freeze have not been met.

The Utility believes the adoption of TURN's proposed accounting changes results in illegal retroactive ratemaking and constitutes an unconstitutional taking of the Utility's property, and violates the federal filed rate doctrine. The Utility also believes the other CPUC decisions are similarly illegal to the extent they would compel the Utility to make payments to the DWR and QFs without providing adequate revenues for such payments. The Utility plans to challenge the decisions in appropriate legal forums.

PG&E Corporation and the Utility recognized a fourth quarter charge to earnings of $6.9 billion ($4.1 billion after tax) to reflect the fact that the Utility could no longer conclude that its generation-related regulatory assets and undercollected purchased power costs were probable of recovery from ratepayers. Further, absent a regulatory judicial, or legislative solution, the Utility cannot conclude that any power purchase costs it incurs during 2001 in excess of revenues from retail rates are probable of recovery through future rates.

Retail Direct Access. Customers participating in direct access may purchase their electric power directly either through (1) competing non-utility retail electric providers such as brokers, marketers, aggregators, or other retailers, or (2) direct negotiated contracts with electric generators. Energy service providers (ESPs) supplying the direct access market had three billing options: (1) consolidated energy supplier billing, under which the utility bills the energy supplier for the services provided directly by the utility to the customer, and the supplier, in turn, provides a consolidated bill to the customer, (2) consolidated distribution company billing, under which the utility places the supplier's energy charge on a distribution bill, or (3) dual billing, under which the energy supplier and the utility bill separately for their own services. All customers (with limited exceptions), whether they choose direct access or not, were required to pay the nonbypassable CTC to be collected by their distribution utility in connection with recovery of the utilities' transition costs. The majority of direct access customers have been small commercial and large industrial customers. In light of the California electricity crisis, many ESPs have returned their direct access customers to Utility service. As of March 30, 2001, the Utility only had 36,641 direct access customers. AB 1X provides that, at a time to be determined by the CPUC, the right of retail customers to procure service from other ESPs will be suspended until the DWR no longer supplies power for retail end use customers. There may be further legislation to address direct access.

Pursuant to CPUC regulations, the Utility has provided a PX energy credit to direct access customers. As wholesale power prices began to increase beginning in June 2000, the level of PX credits increased correspondingly to the point where the credits exceeded the Utility's distribution and transmission charges to direct access customers. Although the Utility paid approximately $39 million in PX credits, the Utility has ceased paying these credits. The Utility believes whether these credits are owed, and if so in what amount, may be affected by the resolution of when the rate freeze ended (the Utility believes its rate freeze ended as early as May 2000 depending on the final valuation of the Utility's hydroelectric generating assets) and by whether the FERC ultimately orders refunds of wholesale prices which have been found by the FERC to be unjust and unreasonable. As of March 29, 2001, the estimated total of accumulated credits potentially owing to direct access customers that have not been paid by the Utility may be as high as $503 million. Three ESPs have filed complaints against the Utility at the CPUC arguing that the Utility violated CPUC orders and demanding payment for credits accumulated for their customers. The large PX credits have reduced revenues which, along with high PX costs, have contributed to the under-collection in the Utility's TRA.

Electric Operating Statistics

At December 31, 2000, the Utility served approximately 4.6 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.

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

The following table shows certain customer information:

Selected Statistics:	2000	1999	1998	1997
Average annual residential usage (kWh)	7,062	6,905	6,776	6,627
Average billed revenues per kWh (cents per kWh):				
Residential	10.46	10.68	10.77	11.88
Commercial	8.48	9.32	9.69	10.15
Industrial(1)	3.02	5.17	5.72	6.09
Agricultural(1)	10.11	10.48	11.42	10.52
Net plant investment per customer ($)	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 earn commodity charges.

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Electric Resources

The Utility's sources of generation during 2000 were as follows: 15% from the Utility's hydroelectric assets, 21% from the Utility's nuclear facilities at Diablo Canyon, 1% from the Utility's fossil-fueled plants, and 63% from QFs and other power suppliers. In 1995, the CPUC issued a decision which required the Utility to "file a plan to voluntarily divest [itself] of at least 50% of [its] fossil generating assets." As an incentive to divest, the CPUC reduced the rate of return on the Utility's generating assets, including its hydroelectric generation assets and Diablo Canyon, to 6.77%. The Utility has sold all but two of its fossil-fueled electric generating plants and has sold all of its geothermal generating facilities. The Utility's own generation resources and contracted for generation resources serve approximately 36% of the Utility's retail electric customers.

Until December 15, 2000, the Utility was required to sell all of its owned generation, and generation purchased by the Utility under long-term contracts with QFs and other power providers, to the PX. The December 15, 2000 FERC order eliminated the requirement that the California investor-owned utilities sell all of their generation into (and buy all of their energy needs from) the PX. The PX suspended the Utility's trading privileges on January 19, 2001 and the PX markets were suspended as of January 31, 2001. Since January 31, 2001, the Utility has been scheduling its own generation through the ISO for use by the Utility's customers. The remainder of the power needed to serve the Utility's customers has been purchased by the DWR or the ISO.

Generating Capacity

Except as otherwise noted below, as of December 31, 2000, Pacific Gas and Electric Company owned and operated the following generating plants, all located in California, listed by energy source:

Generation Type	County Location	Num of U
Hydroelectric:		

Conventional Plants	16 counties in Northern and Central California	1
Helms Pumped Storage Plant	Fresno	
		_
Hydroelectric Subtotal		1
		-
Steam Plants:		
Humboldt Bay	Humboldt	
Hunters Point(1)..	San Francisco	
		_
Steam Subtotal		
		_
Combustion Turbines:		
Hunters Point(1)..	San Francisco	
Mobile Turbines(2)......................................	Humboldt and Mendocino	
		_
Combustion Turbines Subtotal		
		_
Nuclear:		
Diablo Canyon	San Luis Obispo	
		_
Total		1
		=

(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 with a total generating capacity of 3,896 megawatts (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, the CPUC's draft environmental impact report (EIR) reviewing the potential environmental impacts of the proposed auction under the California Environmental Quality Act (CEQA) was issued.

As an alternative to the auction proposal, in August 2000, the Utility and other parties filed an application with the CPUC for approval of a settlement under which the hydroelectric facilities would be transferred to a California-based affiliate of PG&E Corporation at a value of $2.8 billion, subject to a 40-year revenue sharing agreement. In November 2000, the Utility withdrew its support from the settlement. In December 2000, the Utility submitted updated testimony in the valuation proceedings indicating that the market value of the hydroelectric assets ranges from $3.9 billion to $4.2 billion assuming that the assets were sold in a competitive auction or other arm's-length sale. Updated joint testimony was also submitted by the CPUC's Office of Ratepayer Advocates (ORA), TURN, and the California Farm Bureau Federation (CFBF). These parties had previously submitted joint testimony in which they recommended a valuation of $2.665 billion assuming the hydroelectric facilities would be retained by the Utility. Their updated testimony estimates that recent higher market prices result in an increase in the value of the assets by approximately $943 million, although they do not recommend any change to their previous valuation of $2.665 billion. Instead, they recommend that ratepayers receive all future operating profits from hydroelectric generation operations, which, based on higher price forecasts, will ensure that ratepayers obtain the full value of the assets. Further, the joint parties recommend that the amount of the final market valuation that exceeds book value be used to reduce the Utility's undercollected wholesale power purchase costs recorded in the Utility's TRA rather than crediting the Utility's TCBA. The Utility has opposed this proposal, as it would unlawfully delay the completion of transition cost recovery by the Utility as well as delay the end of the rate freeze.

In response to the California wholesale electricity crisis, in January 2001, the California Governor signed Assembly Bill 6 (AB6) which prohibits public utilities from disposing of any generation facility before January 1, 2006. In light of AB6, the hydroelectric valuation proceeding will no longer address the disposition of the hydroelectric facilities. On February 21, 2001, the Utility requested that the CPUC suspend the CEQA review in light of AB6. Absent a resolution suspending the CEQA review, the Utility provided comments on the draft EIR on March 9, 2001.

In its rate stabilization proceeding, the Utility has proposed to defer receiving a portion of its share of profits from its hydroelectric plants until a later time and allow those funds instead to be used to offset uncollected power purchase costs. The Utility has proposed that for the next two years (after which the Utility expects the current supply shortage will be less critical), the Utility sell the output of these facilities directly to its retail distribution customers on an incentive ratemaking basis to lower the costs of procured power for such customers.

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, 2000, Diablo Canyon Units 1 and 2 had achieved lifetime capacity factors of 82% and 84%, 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.

	2001	2002	2003
Unit 1			
Refueling		May	
Startup		June	
Unit 2			
Refueling	April		February
Startup	June		March

Diablo Canyon Ratemaking. Since January 1, 1997, the Utility's sunk costs in Diablo Canyon have been recovered from ratepayers through a sunk cost revenue requirement, at a reduced return on common equity equal to 6.77% that will remain in effect through the end of the transition period. (Sunk costs are costs associated with the facility that are fixed and unavoidable.) The Diablo Canyon sunk costs revenue requirement is being recovered as a transition cost through the TCBA. In connection with the new ratemaking, the CPUC ordered that a financial verification audit of Diablo Canyon plant accounts be performed by an independent accounting firm, and that the CPUC hold a proceeding to review the results of the audit, including any proposed adjustments to Diablo Canyon accounts, following the completion of the audit. The audit was completed in August 1998. In September 2000, the CPUC issued a decision that concluded that because the audit found that Diablo Canyon costs are presented fairly, no further action would be taken and the proceeding would be closed.

Also since January 1, 1997, a performance-based Incremental Cost Incentive Price (ICIP) mechanism has been used to recover Diablo Canyon's operating costs and the cost of capital additions incurred after December 31, 1996. The ICIP mechanism establishes a rate per kWh generated by the facility for the period 1997 through 2001. The CPUC-authorized ICIP price for 2001 is 3.49 cents per kWh, resulting in estimated ICIP revenues of $552 million based on an assumed capacity factor of 83.6%. The estimated sunk cost revenue requirement for 2001 is approximately $1.1 billion. Any variance between ICIP revenues and related costs is reflected in earnings.

After the transition period, Diablo Canyon generation must be sold at the prevailing market price for power. 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 current electric rate freeze for the Utility's customers 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. In the Utility's rate stabilization proceeding (see "Electric Ratemaking" above), parties have proposed that the requirement to establish a sharing methodology be rescinded and that Diablo Canyon be placed on cost of service ratemaking. 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 2001, and the requirement for the enrichment of the uranium hexaflouride to enriched uranium will be met through 2002. The fuel fabrication contract for the two units will supply their requirements for the next seven 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 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, Pacific Gas and Electric Company 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. 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.

In July 1988, the NRC gave final approval to the Utility to store radioactive waste from the nuclear generating unit (Unit 3) at Humboldt Bay Power Plant (Humboldt) at Humboldt 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 $12 million (property damage) and $4 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 $1.7 billion in 2000 dollars ($5.1 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, 2000, $9.3 million ($15.7 million less $6.4 million in expected tax benefits) has 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 Bay Power Plant Unit 3. As of December 31, 2000, $1.7 million ($2.9 million project cost less $1.2 million in expected tax benefits) has been disbursed from the Humboldt Unit 3 non-tax-qualified trust to reimburse the Utility for nuclear decommissioning expenses associated with the dry cask storage facility. Additional licensing and permitting activities are continuing.

As of December 31, 2000, the Utility had accumulated external trust funds with an estimated liquidation value of $1.36 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 is 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. For the year ended December 31, 2000, annual nuclear decommissioning trust contributions collected in rates were $26.47 million. Of this amount, the Utility was able to contribute only $14 million to the trusts in 2000 due to the Utility's liquidity crisis. The Utility expects that it will be required to refund the difference to customers in 2001. The Utility has filed for a new schedule of ruling amount (SRA) with the IRS that would lower the amount collected through rates to $24 million. The IRS has not yet approved the Utility's proposed SRA. If approved, the difference between the previous amount collected in rates and the new amount would be refunded to customers.

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 provided by 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.

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. (The December 15, 2000 FERC order eliminated this mandatory sell requirement.) The Utility has paid these suppliers directly pursuant to price provisions contained in their PPAs. The invoices sent by the PX for the cost to serve the Utility's retail customers included credits for power provided by these suppliers based on electric market prices.

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 Public Utilities Code (PUC) 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 PUC 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 December 2000, energy costs for deliveries from QFs who switched to PX pricing were approximately $375 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 megawatt-hour. 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.

The Utility paid approximately 15 percent of amounts due QFs for deliveries made in December 2000 and January 2001. The Utility made no payment for QF deliveries received in February 2001. On March 27, 2001, the CPUC issued a decision requiring the Utility and the other California investor-owned utilities to pay QFs fully for energy deliveries made on and after the date of the decision. The CPUC decision requires the Utility to pay QFs for energy and capacity deliveries within 15 days following the current monthly billing period instead of the 30 days after the close of the billing period required by the PPAs. The CPUC stated that its change to the payment provision was required to maintain energy reliability in California. The CPUC held that a failure to make a required payment would result in a fine in the amount owed to the QF. The decision also adopts 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. Based on the Utility's preliminary review of the decision, the revised pricing formula would reduce the Utility's 2001 average QF energy and capacity payments from approximately 12.7 cents per kWh to 12.3 cents per kWh.

Most of the PPAs expire on various dates through 2028, though some have no stated expiration date. Deliveries from these power producers account for approximately 23% of the Utility's 2000 electric energy requirements and no single contract accounted for more than 5% of the Utility's energy needs.

As of December 31, 2000, the Utility had commitments to purchase approximately 5,200 MW of capacity under CPUC-mandated PPAs. Of the 5,200 MW, approximately 4,400 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 4,400 MW of operational capacity consists of 2,700 MW from cogeneration projects, 700 MW from wind projects, and 1,000 MW from other projects, including biomass, waste-to-energy, geothermal, solar, and hydroelectric.

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 CTC. At December 31, 2000, the undiscounted future minimum payments under these contracts are approximately $31.5 million for each of the years 2001 through 2004 and a total of $221 million for periods thereafter. Irrigation district and water agency deliveries in the aggregate account for approximately 4.6% of the Utility's 2000 electric energy requirements.

The amount of energy received and the total payments made under all these power purchase contracts were:

	2000	1999	1998	1997

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	($ in millions)			
Kilowatt-hours received	25,446	25,910	25,994	24,389
Energy payments	$ 1,549	$ 837	$ 943	$ 1,157
Capacity payments	$ 519	$ 539	$ 529	$ 538
Irrigation district and water agency payments...	$ 56	$ 60	$ 53	$ 56

Bilateral Agreements. Until August 2000, CPUC decisions required the Utility to purchase power for its retail customers solely through the PX and ISO. On July 21, 2000, the Utility filed an emergency motion with the CPUC seeking authorization to enter into bilateral agreements directly with third parties to purchase power, capacity, and ancillary services, citing the need to better hedge against high power prices in the PX day-ahead and ISO real-time markets and to introduce new supply into California. In its July 2000 request, the Utility proposed that the CPUC adopt prospective reasonableness standards which would allow the CPUC to determine at the time of inception whether a transaction was reasonable per se compared to specific market prices. Without such prospective reasonableness standards, the CPUC can second-guess the Utility's decision to enter into contracts and disallow some or all of those costs deemed after-the-fact to be "unreasonable."

On August 3, 2000, the CPUC approved the Utility's emergency motion and 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 ORA and the CPUC's Energy Division. ORA and the Energy Division rejected the Utility's proposed standards and neither has suggested alternative standards. Despite this stalemate, during September and October 2000, the Utility held an auction soliciting offers for energy purchases at fixed prices for one to five years. In October 2000, the Utility entered into bilateral power purchase contracts with several suppliers. In December 2000, the Utility again solicited offers from power suppliers, but the responses were priced above then-current market prices so the Utility elected not to enter into any contracts at that time. The downgrade of the Utility's credit ratings since December 2000 has effectively barred the Utility from entering into additional long-term contracts.

In its December 15, 2000 order, the FERC noted that it was critical for the CPUC to give timely and predictable approval of the prudence of a balanced portfolio of short- and long-term contracts. 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 PUC 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 as of December 31, 2000 owned approximately 18,376 circuit miles of interconnected transmission lines of 60 kilovolts (kV) to 500 kV and transmission substations having a capacity of approximately 39,859,000 kilovolt-amperes (kVA), including spares, excluding power plant interconnection facilities. Energy is distributed to customers through approximately 115,131 circuit miles of distribution system and distribution substations having a capacity of approximately 23,524,000 kVA.

In connection with electric industry restructuring, in 1998 the utilities relinquished control, but not ownership, of their transmission facilities to the ISO. 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 $178 million in 2000, 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 remedy transmission constraints on the Utility's electric transmission system. Of particular concern are the constraints on Path 15, which is located in the southern portion of the Utility's service area, and serves as the 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 (where the Utility's Diablo Canyon nuclear power plant is located) and Northern California. This often results 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.

The Utility's investment in maintenance and expansion of its transmission system has been growing substantially over the past several years. The Utility anticipates making an additional capital investment of approximately $260 million in its transmission system in 2001. 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.

As a result of the ISO concluding that the available power reserves were precipitously low, the ISO ordered the Utility to implement emergency procedures in the Utility's service territory frequently during the summer 2000 and winter 2001, and as recently as March 2001. On some occasions these measures included rolling outages affecting a large number of retail customers. It is anticipated that a projected power supply shortage for peak demand periods, including the summer of 2001, will result in further rolling outages. To the extent conservation efforts are successful, the need for such emergency measures may be lessened. Depending on the location of the available power supply relative to the load, transmission constraints could exacerbate the supply problem. Completion of the Utility's planned transmission projects before the summer 2001 peak are expected to mitigate most of these constraints.

Most of the Utility's distribution services remain subject to CPUC jurisdiction. The CPUC is considering whether it should pursue further reforms in the structure and regulatory framework governing electricity distribution service.

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 3.8 million gas customers at December 31, 2000. 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. 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. However, the Utility continues to purchase gas as a regulated supplier for those core customers who request it.

At December 31, 2000, the Utility's system consisted of approximately 6,261 miles of transmission pipelines, three gas storage facilities, and approximately 37,958 miles of gas distribution lines. The Utility's Line 400/401 interconnects with the natural gas transmission system of the Utility's sister subsidiary, PG&E Gas Transmission, Northwest Corporation (PG&E GTN). 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 840-mile combined Utility-PG&E GTN pipeline provides about 2,700 million cubic feet per day (MMcf/d) of capacity. More than 1,800 MMCf/d 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/d. 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, 2000, was 3,795 million cubic feet (MMcf). The total volume of gas throughput during 2000 was approximately 937,000 MMcf, of which 281,000 MMcf was sold to direct end-use or resale customers, 49,000 MMcf was used by the Utility primarily for its fossil-fueled electric generating plants, and 606,000 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.

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.

		Years Ended De	
	2000	1999	1998
Customers (average for the year):			
Residential	3,642,266	3,593,355	3,536,
Commercial	203,355	203,342	200,
Industrial	1,719	1,625	1,
Other gas utilities	6	4	
Total	3,847,346	3,798,326	3,738,
Gas supply--thousand cubic feet (Mcf) (in thousands):			
Purchased from suppliers in:			
Canada	216,684	230,808	298,
California	32,167	18,956	17,
Other states	75,834	107,226	122,
Total purchased	324,685	356,990	438,
Net (to storage) from storage	19,420	(980)	(14,
Total	344,105	356,010	423,
Pacific Gas and Electric Company use, losses, etc.(1)	62,960	47,152	129,
Net gas for sales	281,145	308,858	294,
Bundled gas sales and transportation service--Mcf (in thousands):			
Residential	210,515	233,482	223,

Commercial	66,443	70,093	66,
Industrial	4,146	5,255	4,
Other gas utilities	41	28	
Total	281,145	308,858	294,
Transportation service only--Mcf (in thousands):			
Vintage system (Substantially all Industrial)(2)	606,152	484,218	396,
PG&E Expansion (Line 401)(3)	0	0	
Total	606,152	484,218	396,
Revenues (in thousands):			
Bundled gas sales and transportation service:			
Residential	$ 1,680,745	$ 1,542,705	$ 1,414,
Commercial	513,080	448,655	426,
Industrial	35,347	24,638	24,
Other gas utilities	0	77	1,
Bundled gas revenues	2,229,172	2,016,075	1,866,
Transportation only revenue:			
Vintage system (Substantially all Industrial) ...	324,319	267,544	232,
PG&E Expansion (Line 401)	13,392	19,091	42,
Transportation service only revenue	337,711	286,635	274,
Miscellaneous	84,526	(47,311)	41,
Regulatory balancing accounts	131,762	(259,648)	(448,
Operating revenues	$ 2,783,171	$ 1,995,751	$ 1,733,

(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 4,833 MMcf, 1,251 MMcf, 34,169 MMcf, 72,958 MMcf, and 78,552 MMcf for 2000, 1999, 1998, 1997, and 1996, respectively.

(3) Starting in 1998, Vintage system and PG&E Expansion are combined and reported as total transportation service.

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	Years Ended December 31,			
	2000	1999	1998	19
Selected Statistics:				
Average annual residential usage (Mcf)	59	65	63	
Heating temperature--% of normal (1)	101.2	108.5	93.0	
Average billed bundled gas sales revenues per Mcf:				
Residential	$ 7.98	$ 6.61	$ 6.32	$
Commercial	7.72	6.40	6.45	

Industrial	8.53	4.69	5.36	
Average billed transportation only revenue per Mcf:				
Vintage system	0.54	0.66	0.66	
PG&E Expansion (Line 401)	2.04	0.53	0.54	
Net plant investment per customer (2)	$ 1,003	$ 1,011	$ 1,040	$ 1

(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 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 U.S. Secretary of Energy issued a temporary order on January 19, 2001, requiring the gas suppliers to make deliveries to avoid a worsening natural gas shortage emergency. However, this order expired on February 7, 2001, and certain companies, representing about 10% of the Utility's natural gas suppliers, terminated deliveries after the orders expired. 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 (extended to 180 days in a CPUC draft decision issued on February 15, 2001) to secure gas for its core customers. At March 29, 2001, the amount of gas accounts receivables pledged was approximately $900 million. As of March 29, 2001, approximately 30% of the Utility's suppliers of natural gas had signed security agreements with the Utility and discussions were continuing with the Utility's other suppliers. Additionally, the Utility is currently implementing a program to obtain longer-term summer and winter supplies and daily spot supplies.

The Utility has also filed an application with the CPUC to declare a gas emergency, and require one of the Utility's larger gas suppliers to sell incremental gas supplies to the Utility. The gas supplier has protested the application. The CPUC is expected to rule on the application at its meeting on April 19, 2001.

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, 2000, approximately 67% 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, approximately 10% was purchased in California, approximately 21% was purchased in the U.S. Southwest and was transported primarily by the El Paso Natural Gas Company and Transwestern Pipeline Company pipelines, and approximately 2% 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.

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

(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 of 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)."

In January 1998, the CPUC opened a rulemaking proceeding to explore alternative market structures in the natural gas industry in California. In January 2000, the Utility and a broad-based coalition of shippers, consumer groups, marketers, and others filed a settlement with the CPUC which reaffirmed the basic structure of the Gas Accord and would continue the Gas Accord through its original term of December 31, 2002. In May 2000, the CPUC approved the uncontested settlement.

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 $94 million in 2000. This amount includes payments made to PG&E GTN of approximately $46 million in 2000, which are eliminated in the consolidated financial statements of PG&E Corporation.

As a result of regulatory changes, the Utility no longer procures gas for most of its noncore customers, resulting in a decrease in the Utility's need for firm transportation capacity for its gas purchases. The Utility continues to procure gas for almost all of its core customers and, up until February 2001, procured gas for those noncore customers who chose bundled service (core subscription customers). (Core subscription service ended on February 28, 2001, and most former core subscription customers elected to receive bundled service as core customers.) The Utility is continuing its efforts to broker or assign any of its remaining contracted-for but unused interstate and Canadian transportation capacity, including unused capacity held for its core and core-subscription customers.

Under a firm transportation agreement with PG&E GTN that runs through October 31, 2005, the Utility currently retains capacity of approximately 600 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, INC.

PG&E Corporation's wholly owned subsidiary, PG&E National Energy Group, Inc. (NEG), is an integrated energy company with a strategic focus on power generation, new power plant development, natural gas transmission, and wholesale energy marketing and trading in North America.

On December 22, 2000, NEG completed the sale of PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. and their subsidiaries, to El Paso Field Services Company, a subsidiary of El Paso Energy Corporation. The Texas operations that were sold included gas gathering, transportation, and processing facilities, and natural gas liquids (NGL) pipelines. In addition, during 2000, NEG completed the sale of the retail energy services and value-added services businesses of its subsidiary, PG&E Energy Services Corporation.

NEG's ability to anticipate and capture profitable business opportunities created by deregulation will have a significant impact on PG&E Corporation's future operating results. Implementation of PG&E Corporation's national energy strategy depends, in part, upon the opening of energy markets to provide customer choice of supplier. Undue delays in deregulation of the electric generation and natural gas supply business could impact the pace of growth of NEG's businesses.

Integrated Power Generation, and Energy Trading and Marketing Business

NEG manages the operations, fuel supply, and sale of electric output of its owned and leased generating facilities as an integrated portfolio with its contractually controlled generating facilities and its other marketing and trading activities. NEG had a net ownership interest in 5,230 MW of generating capacity as of December 31, 2000. In addition, NEG had 19,993 MW of gas-fired generating facilities in construction or under development for which NEG has secured the necessary turbines. NEG controls the output of 518 MW of operating generating capacity and 3,722 MW of generating capacity in construction or development through various long-term contracts as of December 31, 2000.

NEG's energy marketing and trading activities are focused in markets in which it owns or controls generating facilities and in developed competitive markets. NEG's integrated power generation, and energy marketing and trading business is principally engaged in the following areas:

- ownership and operation of generating facilities,
- new power plant development and construction,
- contractual control of generating capacity,
- energy marketing and trading, and
- risk management.

Ownership and Operation of Generating Facilities. As of December 31, 2000, NEG had ownership or leasehold interests in 19 operating generating facilities with a net generating capacity of 5,230 MW. These facilities include five gas-fired generating facilities with a net generating capacity of 1,055 MW, ten generating facilities that primarily burn coal or waste coal, in some cases in combination with oil or gas, with a net generating capacity of 2,997 MW, three hydroelectric systems or pumped storage facilities with a net generating capacity of 1,166 MW, and one 12 MW wind generating facility. NEG provides operating and management services for 16 of its 19 owned and leased generating facilities.

NEG's generating facilities fall into two categories: merchant plants and independent power projects. Merchant plants sell their electrical output in the competitive wholesale electric market on a spot basis or under contractual arrangements of various terms. Independent power projects sell all or a majority of their electrical capacity and output to one or more third parties under long-term power purchase agreements tied directly to the output of that plant. In order to provide fuel for independent power projects, natural gas and coal supply commitments are typically purchased from third parties under long-term supply agreements. All of the generating facilities developed or placed in operation before 1997 are independent power projects. NEG had a net ownership interest of 1,100 MW in independent power projects as of December 31, 2000. All other generating facilities acquired, placed in operation, or controlled through contracts, during or after 1997 are merchant plants. Generating facilities under construction or in development are expected to be operated as merchant plants.

New Power Plant Development and Construction. NEG manages the development and construction of power generating facilities (sometimes referred to as "greenfield" development), which include natural gas-fired and coal-fired generating facilities, and facilities that use other power generating technologies, including hydroelectric power and wind. NEG considers a generating facility to be under construction once NEG or the lessor has acquired the necessary permits to begin construction, broken ground at the project site, and contracted to purchase the major machinery for the project, including the combustion turbines. In addition, NEG has a number of generating facilities in development. NEG considers a generating facility to be in development when NEG has contractual commitments or options to purchase the turbines necessary to complete the project or when NEG has made substantial progress in site selection, control of the site and permitting. The completion of planned development projects is subject to many factors, including but not limited to changes in governmental regulations, the timing of regulatory and environmental approvals or the failure to obtain such approvals, failure to obtain adequate financing on satisfactory terms, failure to obtain necessary equipment to operate, failure of third party contractors to perform their contractual obligations, a competitor's development of a lower-cost generating plant, fluctuations in natural gas and electricity prices and the ability to successfully manage such price fluctuations, and the risks associated with marketing and selling power in the newly competitive energy market.

As of December 31, 2000 NEG owned or had committed to lease or acquire six generating facilities currently under construction in five states, representing 3,006 MW. These projects are expected to be placed in service in 2001 and 2002 and since year end, NEG has placed 350 MW in commercial operation. In addition, NEG has five generating facilities in advanced development in five states, representing over 5000 MW, which it expects to be able to place into construction during 2001. NEG has secured contractual commitments and options for 60 new combustion turbines for large, gas-fired facilities, representing 19,808 MW of net generating capacity. Ten of these turbines, representing approximately 2,821 MW, are for generating facilities under construction as of December 31, 2000, (the Millennium, Lake Road, La Paloma, and Attala power plant projects). Most of these turbine commitments use the latest generation of combustion technology, commonly known as G technology.

The Lake Road and La Paloma facilities are being constructed by Alstom Power, Inc. (Alstom) under fixed price construction contracts with guaranteed dates for commercial operations. Alstom has advised 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. 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.

NEG also encountered start-up problems with the Siemens Westinghouse G technology turbine installed at its Millennium facility. These problems have delayed the expected date of commercial operations for this facility, which began commercial operations in April 2001. NEG does not expect that the start-up problems with the Siemens Westinghouse G technology turbine installed at the Millennium facility will result in a reduction in the guaranteed level of efficiency or output.

The construction contracts for each of the Millennium, Lake Road, and La Paloma projects provide for liquidated damages. However, these liquidated damages will not offset fully the financial impact associated with the delays of these turbines in achieving their expected level of performance.

Contractual Control of Generating Capacity. NEG has increased its generating capacity through contractual control of the electric output of generating facilities owned by others. NEG has executed various long-term contracts representing 4,240 MW of generating capacity, which result in control of 518 MW of operating generating capacity and 3,722 MW of generating capacity in construction or development as of December 31, 2000. The primary method of achieving contractual control of generating capacity is through tolling agreements. Tolling agreements establish a contractual relationship that grants NEG the right to use a third party's generating facility to convert NEG's fuel, typically natural gas, to electricity. NEG has the right to decide the timing and amount of electricity production within agreed operating parameters. The owner of the facility typically 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 or other operating factors.

The terms of the seven tolling agreements NEG has entered into as of December 31, 2000, range from 10 to 25 years commencing on the date of initial commercial operations of the generating facility. Most of the generating facilities are under construction or in development, with commercial operations expected to commence between 2001 and 2004. These tolling agreements provide NEG with control of gas-fired plants in the Mid-Atlantic, Midwestern, Southern, and Western regions of the United States.

Energy Marketing and Trading. NEG's marketing and trading operations manage fuel supply procurement and sale of electrical output of NEG's owned and controlled generating facilities as an integrated portfolio with NEG's trading positions. During the year ended December 31, 2000, NEG sold approximately $283 million MW hours of power and an average of over 6.5 Bcf of natural gas per day.

Through over-the-counter and futures markets across North America, NEG engages in the marketing and trading of (1) electric energy, (2) capacity and ancillary services, (3) fuel and fuel services such as transport and storage, (4) emission credits, and (5) other related products. NEG markets and trades all types of fuels necessary for its owned and controlled generating facilities, including natural gas, coal, and oil.

NEG uses derivative financial instruments to provide flexible pricing to its customers and suppliers and manage its purchase and sale commitments, including those related to NEG's owned and controlled generating facilities, gas pipelines, and storage facilities. NEG also uses derivative financial instruments to reduce its exposure relative to the volatility of market prices. Financial instruments are also used to hedge interest rate and currency volatility.

NEG also evaluates and implements highly structured long-term and short-term transactions. These transactions include (1) management of third party energy assets, (2) short-term tolling arrangements, (3) management of the requirements of aggregated customer load through full requirement contracts, (4) restructured independent power project contracts, and (5) purchase and sale of transportation, storage and transmission rights through auctions and over-the-counter markets.

NEG's energy marketing and trading operations provide the following products and services:

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

Natural Gas Marketing and Trading. 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 NEG's owned and controlled generating facilities and its obligations under long-term structured transactions. NEG also buys, sells and arranges transportation to and from third parties under a variety of short-term agreements. 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. NEG sold an average of 6.5 Bcf per day of natural gas in 2000 transported on 44 pipelines throughout North America.

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. NEG also enters into various short-term and long-term firm and interruptible agreements for natural gas storage in order to provide peak delivery services to satisfy winter heating and summer electric generating demands.

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

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 this consumer demand, an increasing number of companies aggregate blocks of customers, buy power at wholesale and deliver it to end-user consumers. As part of NEG's integrated generation, energy marketing and trading business, 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.

NEG's largest load management contracts are the wholesale standard offer service agreements with affiliates of New England Power, from whom NEG purchased 4,800 MW of owned and controlled generating capacity in 1998. Under the wholesale standard offer service agreements, NEG supplies a fixed percentage of the full requirements of the retail customers of New England Power's affiliates who receive standard offer service in Massachusetts and Rhode Island. The price NEG receives for the electricity it provides under the wholesale standard offer service agreements has a fixed floor (which escalates automatically over time) and is subject to upward escalation if the price of natural gas and fuel oil exceed a specified threshold. NEG receives a fixed price for the electricity it provides under the standard offer service agreements. Standard offer service is intended to stimulate the retail electric markets in these states by gradually increasing the fixed price of electricity under this service. The fixed price increases by a specified amount each year and also increases if the prices of natural gas and fuel oil exceed a specified threshold. These retail customers may select alternative suppliers at any time. NEG's sales volumes and revenues under the wholesale standard offer service agreements totaled 13.2 million MW hours and $563.4 million in 2000. 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.

Fuel Supply, Transport, and Electric Transmission Management. 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.

Risk Management Controls. NEG manages the risk associated with its marketing and trading operations through a comprehensive set of policies and procedures involving senior levels of its management. NEG's senior management sets value-at-risk limitations and regularly reviews NEG's risk management policies and procedures. Within this framework, NEG's risk management committee oversees all of NEG's marketing and trading activities. All of NEG's risk management models are validated by third party experts, such as independent accountants and consultants with extensive experience in specific derivative applications.

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NEG's risk management group is structured as a separate unit in its organization. This management group is responsible for the day-to-day enforcement of the policies, procedures and limits of its trading and marketing activities and evaluating the risks inherent in proposed transactions. These key activities include evaluating and monitoring the creditworthiness of trading counterparties, setting and monitoring volumetric and loss limits on portfolio risks, establishing and monitoring trading limits on products, as well as on individual traders, validating trading transactions, and performing daily portfolio valuation reporting including mark-to-market valuation.

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Description of Generating Facilities. The following table provides information regarding each of NEG's owned or controlled operating generating facilities, as well as those under construction as of December 31, 2000.

Total	NEG Net Interest in Total

Generating Facility	State	MW	MW(1)	Structure	Fuel	Primary Output Sa
New England Region						
Brayton Point Station	MA	1,599	1,599	Owned	Coal/Oil	Competitive
Salem Harbor Station	MA	745	745	Owned	Coal/Oil	Competitive
Bear Swamp Facility	MA	599	599	Leased	Water	Competitive
Manchester St. Station	RI	495	495	Owned	Natural Gas	Competitive
Connecticut River System ...	NH/VT	484	484	Owned	Water	Competitive
Masspower	MA	267	35	Owned	Natural Gas	Power Purchase
Pittsfield(2)	MA	173	143	Leased	Natural Gas	Power Purchase and Competiti
Milford Power(2)	MA	171	96	Contract	Natural Gas	Competitive
Deerfield River System	MA/VT	83	83	Owned	Water	Competitive
Pawtucket Power(2)	RI	69	69	Contract	Natural Gas	Competitive
14 Smaller Facilities(2) ...	Various	193	193	Contract	Renewable/Waste	Competitive
Millennium(3)	MA	360	360	Owned	Natural Gas	Competitive
Lake Road	CT	840	840	Leased	Natural Gas	Competitive
Subtotal		6,078	5,741			
Mid-Atlantic and New York Region						
Selkirk	NY	345	145	Owned	Natural Gas	Power Purchase and Competiti
Carneys Point	NJ	269	135	Owned	Coal	Power Purchase
Logan	NJ	225	113	Owned	Coal	Power Purchase
Northampton	PA	110	55	Owned	Waste Coal	Power Purchase
Panther Creek	PA	80	40	Owned	Waste Coal	Power Purchase
Scrubgrass	PA	87	44	Owned	Waste Coal	Power Purchase
Madison	NY	12	12	Owned	Wind	Competitive
Liberty	PA	530	530	Contract	Natural Gas	Competitive
Subtotal		1,658	1,074			
Midwest Region						
Georgetown	IN	240	160	Contract	Natural Gas	Competitive
Ohio Peakers	OH	141	141	Owned	Natural Gas	Competitive
Subtotal		381	301			
Southern Region						
Indiantown	FL	360	126	Owned	Coal	Power Purchase
Cedar Bay	FL	269	135	Owned	Coal	Power Purchase
Attala	MS	500	500	Owned	Natural Gas	Competitive
SRW(4)	TX	420	250	Contract	Natural Gas	Competitive
Subtotal		1,549	1,011			
Western Region						
Hermiston	OR	474	237	Owned	Natural Gas	Power Purchase
Colstrip	MT	40	5	Owned	Waste Coal	Power Purchase
Mountain View	CA	44	44	Owned(5)	Wind	Competitive
La Paloma	CA	1,121	1,121	Leased	Natural Gas	Competitive
Subtotal		1,679	1,407			
Total		11,345	9,534			

(1) NEG's net interest in an independent power project is determined by

multiplying NEG's percentage of the project's expected cash flow by the project's total MW.

(2) NEG controls all or a portion of the output of 17 smaller generating facilities under long-term power purchase agreements. In return for NEG's assumption of the purchase obligations under these agreements from the New England Power Company, the New England Power Company has agreed to pay an average of $111 million per year through January 2008 to offset NEG's payment obligations under these contracts. The facilities NEG controls in whole or in part through these power purchase agreements include the Milford Power Project, the Pittsfield Project, the Pawtucket Power Project, and 14 other small generating facilities with a total generation capacity of 193 MW fueled by municipal waste, water, landfill gas, or wood. The power purchase agreements terminate between 2009 and 2029.

(3) Millenium achieved commercial operation in April 2001.

(4) An NEG subsidiary entered into a contract with SRW Cogeneration Limited partnership dated as of July 30, 1999 pursuant to which NEG would control 250 MW of a 420 MW cogeneration facility the limited partnership is building and is to operate. The limited partnership has provided NEG with notice of its purported termination of the contract, which NEG is contesting.

(5) NEG has executed a contract to purchase the Mountain View facility. The purchase has not yet closed.

Competition. Some of the competitive factors affecting the results of operations of NEG's owned and controlled generating facilities include new market entrants, construction by others of more efficient generating facilities and the number of years and

extent of operations in a particular energy market. Other competitors operate generating facilities in the regions where NEG has invested in generation facilities. Although local permitting and siting issues often reduce the risk of a rapid growth in supply of generating capacity in any particular region, projects are likely to be built over time which will increase competition and lower the value of some of NEG's generating facilities.

There is also significant competition for the development and acquisition of domestic unregulated generating facilities. NEG competes against a number of other participants in the non-utility power generation industry. Competitive factors relevant to the non-utility power industry include financial resources, development expenses, and regulatory factors. Some of NEG's competitors have greater financial resources than NEG has.

NEG's energy marketing and trading operations compete with other energy merchants 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, NEG anticipates that its energy, marketing and trading operations will experience greater competition and downward pressure on per-unit profit margins.

Natural Gas Transmission Business

NEG's natural gas transmission business currently consists of the PG&E GT-Northwest (PG&E GTN) pipeline, a 5.2% interest in the Iroquois Gas Transmission System and the North Baja pipeline under development.

The following table summarizes NEG's gas transmission pipelines:

Pipeline Name	Location	In Service Date	Capacity (MMcf/d)	12 month capacity factor
PG&E GT-Northwest	ID, OR, WA	1961	2,700	96%
Iroquois Gas Transmission System	NY	1991	900	95%
North Baja	AZ, CA,	2002	500	N/A

PG&E GT-Northwest (PG&E GTN). PG&E GTN owns and operates the PG&E GTN pipeline. This pipeline consists of over 1,300 miles of natural gas transmission mainline pipe with a capacity of 2.7 Bcf of natural gas per day. The PG&E GTN pipeline begins at the British Columbia-Idaho border, extends through northern Idaho, southeastern Washington and central Oregon, and ends on the Oregon-California border where it connects with other pipelines. This pipeline is the largest transporter of Canadian natural gas into the United States. For the year ended December 31, 2000, this pipeline transported 967 Bcf of natural gas, resulting in a 5% growth in transported volumes from the previous year. Since this pipeline commenced commercial operations in 1961, it has experienced a five-fold increase in peak system capacity. The PG&E GTN pipeline is the only interstate pipeline directly connecting the large and rapidly growing gas markets of California, Nevada, and the Pacific Northwest with the abundant natural gas supplies of the Western Canadian Sedimentary Basin and potentially the natural gas rich North Slope of Alaska and Northwest Territories of Canada. The pipeline transports over 30% of California's natural gas demand requirements and over 20% of the Pacific Northwest natural gas demand requirements.

The mainline system of the PG&E GTN pipeline consists of two parallel pipelines with 13 compressor stations totaling approximately 414,450 horsepower. This dual-pipeline system consists of approximately 639 miles of 36-inch mainline pipe and approximately 590 miles of 42-inch mainline pipe. The original pipeline commenced commercial operations in 1961 and was expanded throughout the 1960's and 1970, 1981, 1993, 1995 and 1998. The PG&E GTN pipeline includes two laterals, the Coyote Springs Lateral that supplies natural gas to Portland General Electric Company and the Medford Lateral that supplies natural gas to Avista Utilities. This pipeline interconnects with facilities owned by the Utility at the Oregon-California border and with interstate pipelines in northern Oregon, eastern Washington, and southern Oregon. It also delivers gas along various mainline delivery points to two local gas distribution companies of various mainline delivery points.

The PG&E GTN pipeline 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. The pipeline's long-term capacity is 100% committed to firm transportation services agreements with terms in excess of one year. The remaining terms of these agreements range between one and 26 years with a volume-weighted average of approximately 13 years. In addition, due to weather, maintenance schedules, and other conditions, additional firm capacity may become available on a short-term basis. Interruptible transportation is offered when short-term capacity is available due to a firm transportation customer not fully utilizing its committed capacity. Hub services are also offered, which allow customers the ability to park or lend volumes of gas on the pipeline.

The PG&E GTN pipeline currently provides transportation services for over 65 customers, including local retail gas distribution utilities, electric utilities that utilize natural gas to generate electricity, natural gas marketing companies that purchase and resell natural gas on a wholesale and retail basis, natural gas producers, and industrial companies. The customers are responsible for securing their own gas supplies and delivering them to the pipeline system. The customers' natural gas supplies are transported either to downstream pipelines and distribution companies or directly to points of consumption.

PG&E GTN's current rates were set in a rate settlement approved by the FERC in September 1996.

North Baja Pipeline. NEG recently joined with Sempra Energy International and Mexico's Proxima Gas, S.A. de C.V. to develop a 215-mile pipeline that will supply natural gas to Northern Mexico and Southern California. This pipeline will begin at an interconnection with El Paso Natural Gas Company near Ehrenberg, Arizona, traverse southeastern California and northern Baja California, Mexico and terminate at an interconnection with the Rosarito Pipeline south of Tijuana. An application has been filed with the FERC for a certificate to build the 80-mile U.S. segment of this proposed $230 million project. Sempra Energy International and Proxima Gas will direct development of the 135-mile Mexico segment. This pipeline will have an initial capacity of 500 million cubic feet per day with expansion capability to 800 million cubic feet per day.

NEG has signed agreements with five anchor customers to transport almost 90% of the projected daily capacity of 500,000 million cubic feet of natural gas. The average term of these agreements is 20 years. NEG is continuing discussions and negotiations with other potential customers. This pipeline is projected to be in service by the fourth quarter of 2002. In its initial design, this pipeline is intended primarily to serve electric generating needs in northern Mexico and Southern California, as well as industrial and local distribution company load along the Mexico segment. Further, NEG believes that this pipeline will also have the potential to serve delivery points along its entire route.

Competition. NEG's gas transmission business competes with other pipeline companies for transportation customers on the basis of transportation rates, access to competitively priced gas supply and growing markets served by its pipelines, 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 PG&E GTN pipeline accesses natural gas supplies from Western Canada and serves markets in the Pacific Northwest, California, and Nevada. PG&E GTN competes with other pipelines to access natural gas supplies in Western Canada, the Rocky Mountain, the Southwest, and British Columbia.

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

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. This 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 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 and geothermal generation facilities that have been sold. See "Utility Operations--Electric Utility Operations--California Electric Industry Restructuring--Voluntary Generation Asset Divestiture" 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. As a result of the Utility's divestiture of most of its fossil-fueled power plants and its geothermal generation facilities, the Utility's oxides of nitrogen (NOx) emission reduction compliance costs have been reduced significantly.

Air Quality

Pacific Gas and Electric Company's thermal electric generating plants are subject to numerous air pollution control laws, including the California Clean Air Act (CCAA) with respect to emissions. Pursuant to the CCAA 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 Gas Accord authorizes $42 million to be included in rates through 2002 for gas NOx retrofit projects related to natural gas compressor stations on Pacific Gas and Electric Company'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 $101 million from 2001 through 2004. The Utility is planing 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.

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Compliance by NEG affiliates with certain future regulatory requirements limiting the total amount of NOx emissions from its fossil-fueled power plants is expected to be achieved through installation of additional controls, fuel switching, and purchase of NOx allowances. USGenNE has agreed to be bound by a number of state and regional initiatives that will require it to achieve significant reductions of sulfur dioxide (SO_2) and NOx emissions by the time its older fossil-fueled power plants have been in operation for 40 years or by 2010, whichever comes first. It is expected that USGenNE can meet these requirements through utilization of allowances it currently owns, installation of additional controls, or purchase of additional allowances. (SO_2 allowances are emission credits that are traded in a national market under the United States Environmental Protection Agency's (EPA) Acid Rain Program. NOx allowances are emission credits that are traded in a regional market consisting of seven Northeast states known as the Ozone Transport Region.)

In October and November 1999, the EPA and several states filed suits or announced their intention to file suits against a number of coal-fired power plants in Midwestern and Eastern states. These suits relate to alleged violations of the Clean Air Act. More specifically, they allege violations of the deterioration prevention and non-attainment provisions of the Clean Air Act's new source review requirements arising out of certain physical changes that may have been made at these facilities without first obtaining the required permits.

In May 2000, USGenNE received a request for information pursuant to Section 114 of the Clean Air Act from the EPA seeking detailed operating and maintenance history for the Salem Harbor and Brayton Point power plants, which USGenNE acquired in 1998 from the New England Electric System (NEES). USGenNE believes that this request for information is part of the EPA's industry-wide investigation of coal-fired electric power generators to determine compliance with environmental requirements under the Clean Air Act associated with repairs, maintenance, modifications, and operational changes made to coal-fired facilities over the years. If the EPA were to find that there were physical changes made in the past that were undertaken without first receiving the required permits under the Clean Air Act, then penalties may be imposed and further emission reductions might be necessary at these plants.

A new ambient air quality standard was adopted by the EPA in July 1997 to address emissions of fine particulate matter. It is widely understood that attainment of the fine particulate matter standard may require reductions in NOx and SO_2, although under the time schedule announced by the EPA when the new standard was adopted, non-attainment areas were not to have been designated until 2002 and control measures to meet the standard were not to have been identified until 2005. In May 1999, the United States Court of Appeals for the District of Columbia Circuit held that Section 109(b)(1) of the Clean Air Act, the section of the Clean Air Act requiring the promulgation of national ambient air quality standards, as interpreted by the EPA, was an unconstitutional delegation of legislative power. The Court of Appeals remanded both the fine particulate matter standard and the revised ozone standard to allow the EPA to determine whether it could articulate a constitutional application of Section 109(b)(1). On February 27, 2001, the Supreme Court, in Whitman v. American Trucking Associations, Inc., reversed the Circuit Court's judgment on this issue and remanded the case to the Court of Appeals to dispose of any other preserved challenges to the particulate matter and ozone standards. Accordingly, as the final application of the revised particulate matter ambient air quality standard is potentially subject to further judicial proceedings, the impact of this standard on the Utility's and NEG's facilities is uncertain at this time. If an ambient air quality standard for fine particulates is promulgated, further NOx and SO2 reductions may be required for those Utility and NEG facilities located in areas where sampling indicates the ambient air does not comply with the final standards that are adopted.

Since the adoption of the United Nations Framework on Climate Change in 1992, there has been worldwide attention with respect to greenhouse gas emissions. In December 1997, the Clinton Administration participated in the Kyoto, Japan negotiations, where the basis of a Climate Change treaty was formulated. Under the treaty, known as the Kyoto Protocol, the United States would be required, by 2008-2012, to reduce its greenhouse gas emissions by 7% from 1990 levels. However, because of opposition to the treaty in the United States Senate, the Kyoto Protocol has not been submitted to the Senate for ratification. If the U.S. Senate ultimately ratifies the Kyoto Protocol and greenhouse gas emission reduction requirements are implemented, the resulting limitations on power plant carbon dioxide emissions could have a material adverse impact on all fossil fuel-fired facilities, including Utility and NEG facilities.

The EPA has announced that it will regulate steam electric generating plants under Title III of the Clean Air Act, which addresses emissions of hazardous air pollutants from specific industrial categories. Power plants are a source of mercury air emissions. The EPA recently signed a regulatory finding that commits it to propose a mercury-emissions rule applicable to fossil-fuel fired power plants by 2003 and to promulgate a final rule by 2004. According to this regulatory finding, affected facilities will have to comply with this final rule in 2007-2008. The rulemaking process will likely include significant stakeholder and public participation both before and after the emission standards are proposed. The applicable control level is uncertain, as is the cost of these future rules.

In addition to the EPA, states may impose more stringent air emissions requirements. The Commonwealth of Massachusetts is considering the adoption of more stringent air emission reductions from electric generating facilities. If adopted, these requirements will impact Salem Harbor and Brayton Point. NEG has proposed an emission reduction plan that may include modernization of the Salem Harbor power plant and use of advanced technologies for emissions removal. It is also studying various advanced technologies for emissions removal for the Brayton Point power plant.

NEG currently estimates that USGenNE's total capital cost for complying with the requirements described here will be approximately $300 million.

Water Quality

Pacific Gas and Electric Company's existing power plants, including Diablo Canyon, 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 National Pollutant Discharge Elimination System (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.

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

NEG'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. As to the facilities for which their NPDES permit has 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 USGenNEs cost to comply with the new permit conditions could be as much as $55 million through 2005.

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 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

PG&E Corporation subsidiaries assess, on an ongoing basis, measures that may need to be taken to comply with 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 Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), along with other state hazardous waste laws and other environmental requirements.

One part of this 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 2001. 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 impact 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, Pacific Gas and Electric Company 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 Pacific Gas and Electric Company 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, 2000, the Utility expected to spend $320 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.) The Utility had an accrued liability of $294 million at December 31, 2000, representing the discounted value of these costs. Environmental remediation at identified sites may be as much as $462 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.

USGenNE acquired the onsite environmental liability associated with its acquisition of electric generating facilities from NEES, but did not acquire any offsite liability associated with the past disposal practices at the acquired facilities. NEG has obtained pollution liability and environmental remediation insurance coverage to limit the financial risk associated with the on-site pollution liability at all of its facilities.

During April 2000, an environmental group served various affiliates of NEG, including USGenNE, with a notice of intent to file a citizen's suit under RCRA. The group stated that it planned to allege that USGenNE, as the generator of fossil fuel combustion wastes at Salem Harbor and Brayton Point, has contributed and is contributing to the past and present handling, storage, treatment and disposal of wastes at those facilities which may present an imminent and substantial endangerment to the public health or the environment. During September 2000, USGenNE signed a series of agreements with the Massachusetts Department of Environmental Protection and the environmental group that address and resolve these matters. The agreements, which have been filed in federal court and are now incorporated in a consent decree, require, among other things, that USGenNE alter its existing waste water treatment facilities at both facilities by replacing certain unlined treatment basins, submit and implement a plan for the closure of such basins, and perform certain environmental testing at the facilities. These activities are now well underway. The cost of these activities is expected to be approximately $21 million.

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 where 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, 2000, the Utility has recovered from ratepayers approximately $114 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 $53 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 $320 million accrued liability at December 31, 2000 mentioned above includes (1) $140 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 2000 Annual Report to Shareholders), and (2) $180 million related to remediation costs for those generation facilities that the Utility still owns. Of the $320 million environmental remediation liability, the Utility has recovered $168 million through rates, and expects to recover another $87 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 $83 million through December 31, 2000), 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 by December 2001.

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 Pacific Gas and Electric Company's LEV program for the six-year period beginning in 1996. The CPUC's decision on electric industry restructuring found that the costs of utility LEV programs should continue to be collected by the utility for the duration of the six-year period. The Utility continues to run its LEV program as funded. Annual LEV accomplishment reports are filed with the CPUC on November 1.

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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 in the U.S. Bankruptcy Court for the Northern District of California. 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 2000 Annual Report to Shareholders, which portions are incorporated herein by reference and filed as Exhibit 13 to this report.

Pacific Gas and Electric Company vs. California Public Utilities Commissioners

On November 8, 2000, Pacific Gas and Electric Company filed a lawsuit in the United States District Court for the Northern District of California against the CPUC commissioners, asking the court to declare that the federally approved wholesale power costs 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 was $6.6 billion. (As described above, the Utility recognized a fourth quarter 2000 charge to earnings of $6.9 billion ($4.1 billion after tax), reflecting the write-off of undercollected power purchase costs and other generation-related regulatory assets.) The 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 United States 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 United States Constitution.

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 March 19, 2001, the court heard argument on the CPUC's motion to dismiss the case. The judge took the matter under submission.

Wilson vs. PG&E Corporation and Pacific Gas and Electric Company

On February 13, 2001, two complaints were filed against PG&E Corporation and Pacific Gas and Electric Company in the Superior Court of the State of California, San Francisco County: Richard D. Wilson v. Pacific Gas and Electric Company et al. ("Wilson I"), and Richard D. Wilson v. Pacific Gas and Electric Company et al., ("Wilson II").

In Wilson I, the plaintiff alleges that in 1998 and 1999, PG&E Corporation violated its fiduciary duties and California Business and Professions Code Section 17200 by causing the Utility to repurchase shares of Pacific Gas and Electric Company common stock from PG&E Corporation at an aggregate price of $2.326 billion. The complaint alleges an unlawful business act or practice under Section 17200 because these repurchases allegedly violated PG&E Corporation's fiduciary duties, a first priority

capital requirement allegedly imposed by the CPUC's decision approving the formation of a holding company, and also an implicit public trust imposed by AB 1890, which granted authority for the issuance of rate reduction bonds. The complaint seeks to enjoin the repurchase by the Utility of any more of its common stock from PG&E Corporation or other entities or persons unless good cause is shown, and seeks restitution from PG&E Corporation of $2.326 billion, with interest, on behalf of the Utility. The complaint also seeks an accounting, costs of suit, and attorney's fees.

In Wilson II, the plaintiff alleges that PG&E Corporation, the Utility, and other subsidiaries have been parties to a tax-sharing arrangement under which PG&E Corporation annually files consolidated federal and state income tax returns for, and pays, the income taxes of PG&E Corporation and participating subsidiaries. According to the plaintiff, between 1997 and 1999, PG&E Corporation collected $2.957 billion from the Utility under this tax-sharing arrangement, but paid only $2.294 billion (net of refunds) to all governments under the tax-sharing arrangement. Plaintiff alleges that these monies were held under an express and implied trust to be used by PG&E Corporation to pay the Utility's share of income taxes under the tax-sharing arrangement. Plaintiff alleges that PG&E Corporation overcharged the Utility $663 million under the tax-sharing arrangement and has declined voluntarily to return these monies to the Utility, in violation of the alleged trust, the alleged first priority capital condition, and California Business and Professions Code Section 17200. The complaint seeks to enjoin PG&E Corporation from engaging in the activities alleged in the complaint (including the tax-sharing arrangement), and seeks restitution from PG&E Corporation of $663 million, with interest, on behalf of the Utility. The complaint also seeks an accounting, costs of suit, and attorney's fees.

PG&E Corporation and the Utility believe these complaints to be without merit. The Utility filed a notice of automatic stay on April 11, 2001, pursuant to the Bankruptcy Code. PG&E Corporation believes that these actions also are stayed against PG&E Corporation. PG&E Corporation and the Utility are unable to predict whether the outcome of this litigation, if it were to proceed, will have a material adverse affect on their 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.

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 position or results of operations.

Compressor Station Chromium Litigation

Pacific Gas and Electric Company is currently a defendant in nine civil actions pending in California courts. These cases are (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 on July 25, 2000 in Los Angeles Superior Court, (5) Baldonado vs. Pacific Gas and Electric Company, filed On October 25, 2000 in Los Angeles Superior Court, (6) Gale v. Pacific Gas and Electric Company, filed on January 30, 2001 in Los Angeles Superior Court, (7) Monice v. PG&E, filed March 15, 2001, in San Bernardino County Superior Court, (8) Puckett v. PG&E, filed March 30, 2001, in Los Angeles Superior Court, and (9) Alderson, et al. v. PG&E Corporation, Pacific Gas and Electric Company, Betz Chemical Company, et al., filed April 11, 2001, in Los Angeles Superior Court. PG&E has not yet been served with the complaint in Gale v. PG&E, Puckett v. PG&E, or Alderson v. PG&E. There are now approximately 1,150 plaintiffs in the compressor station chromium litigation with claims against the Utility. PG&E Corporation has been named as a defendant in Alderson v. PG&E, et al., a complaint brought on behalf of approximately 100 plaintiffs. PG&E Corporation has not yet been served with the complaint. Betz Chemical Company (Betz), the supplier of water treatment products containing chromium used at the gas compressor stations, also was named as a defendant in some of these cases. During 2000, pursuant to a settlement that Betz reached with the approximately 1,650 plaintiffs suing Betz, the Utility received a credit of up to $40 million to be allocated among the approximately 900 plaintiffs suing the Utility at the time of the Betz settlement. The credit will apply to future awards of damages against the Utility with respect to all claims and causes of actions by these plaintiffs except claims for punitive or exemplary damages.

Each of the complaints alleges personal injuries and seek 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 Utility employees 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 18 trial test plaintiffs and 2 alternates in the Aguayo, Acosta, and Aguilar cases (the "Aguayo Litigation"). 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 the Aguayo Litigation has been set for July 2, 2001, in Los Angeles Superior Court, the Utility's Chapter 11 bankruptcy filing on April 6, 2001, automatically stayed all proceedings.

The Utility is responding to the complaints and asserting affirmative defenses. The Utility will pursue factual defenses including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged and appropriate legal defenses including statute of limitations or exclusivity of workers' compensation laws. At this stage of the proceedings, 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.

There has been heightened media attention to the chromium litigation for a variety of reasons. In a letter dated March 27, 2001, the California Department of Health Services asked the California Environmental Protection Agency's Office of Environmental Health Hazard Assessment, ("OEHHA") to establish a public health goal for chromium 6 in drinking water. In turn, OEHHA has asked the University of California to establish a blue-ribbon panel of scientists to study the potential of chromium 6 to cause cancer when ingested. These regulatory developments followed in part from substantial media attention concerning the presence of chromium 6 in certain water sources in Los Angeles, where the Aguayo Litigation is pending. The chromium issues have also been mentioned in media stories concerning the California energy crisis. All of this media and regulatory attention has the potential to adversely impact the Utility's defense of these cases.

PG&E Corporation believes that the ultimate outcome of this matter will not have a material adverse impact on its or the Utility's future financial position or results of operations. See Note 15 of the "Notes to Consolidated Financial Statements" beginning on page 83 of the 2000 Annual Report to Shareholders, portions of which are filed as Exhibit 13 to this report.

Texas Franchise Fee Litigation

On December 22, 2000, NEG completed the sale of PG&E GTT to El Paso Energy Field Services, Inc., a subsidiary of El Paso Energy Corporation. The PG&E GTT entities which were sold included the defendants in several cases which have been referred to as the Texas Franchise Fee Litigation in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 1999 and previous reports filed with the Securities and Exchange Commission. Only one PG&E Corporation affiliate, PG&E Energy Trading--Gas Corporation, remains as a nominal defendant in some of these cases and any potential liability of this entity is expected to be immaterial.

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, 2000	Position
R. D. Glynn, Jr.	58	Chairman of the Board, Chief Executive Officer, and
T. G. Boren	51	Executive Vice President; Chairman, President, and National Energy Group, Inc.
P. A. Darbee	48	Senior Vice President, Chief Financial Officer, and
T. W. High	53	Senior Vice President, Administration and External
P. C. Iribe	50	Senior Vice President; President and Chief Operatin National Energy Group, Inc.
T. B. King	39	Senior Vice President; President and Chief Operatin National Energy Group, Inc.
L. E. Maddox	45	Senior Vice President; President and Chief Operatin Energy Group, Inc.
G. R. Smith	52	Senior Vice President; President and Chief Executiv and Electric Company
G. B. Stanley	54	Senior Vice President, Human Resources
B. R. Worthington	51	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
R. D. Glynn, Jr.	Chairman of the Board, Chief Executive Officer, and President	January 1, 19
	Chairman of the Board, Pacific Gas and Electric Company	January 1, 19
	President and Chief Executive Officer	June 1, 1997
	President and Chief Operating Officer	December 18,
	President and Chief Operating Officer, Pacific Gas and Electric Company	June 1, 1995
T. G. Boren	Executive Vice President	August 1, 199
	Chairman, President, and Chief Executive Officer, PG&E National Energy Group, Inc.	July 1, 2000
	President, and Chief Executive Officer, PG&E National Energy Group, Inc.	August 1, 199
	President and Chief Executive Officer, Southern Energy, Inc.	February 18,
	Executive Vice President, Southern Company	June 1, 1999

	Senior Vice President, Southern Company	February 16,
	Vice President, Southern Company	July 17, 1995
P. A. Darbee	Senior Vice President, Chief Financial Officer, and Treasurer	September 20,
	Vice President and Chief Financial Officer, Advance Fibre Communications, Inc.	June 30, 1997
	Vice President, Chief Financial Officer, and Controller, Pacific Bell	January 10, 1

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Name	Position	Per
T. W. High	Senior Vice President, Administration and External Relations	June 1, 1997 t
	Senior Vice President, Corporate Services, Pacific Gas and Electric Company	June 1, 1995 t
P. C. Iribe	Senior Vice President	January 1, 199
	President and Chief Operating Officer, East Region, PG&E National Energy Group, Inc.	April 6, 2000
	President and Chief Operating Officer, PG&E Generating Company (formerly known as U.S. Generating Company)	November 1, 19
	Executive Vice President and Chief Operating Officer, U.S. Generating Company	September 1, 1
	Executive Vice President, Marketing, Development, and Asset Management, U.S. Generating Company	May 17, 1994 t
T. B. King	Senior Vice President	January 1, 199
	President and Chief Operating Office, West Region, PG&E National Energy Group, Inc.	April 6, 2000
	President and Chief Operating Officer, PG&E Gas Transmission Corporation	November 23, 1
	President and Chief Operating Officer, Kinder Morgan Energy Partners, L.P.	February 14, 1
	Vice President, Commercial Operations--Midwest Region, Enron Liquid Services Corporation	July 1, 1995 t
L. E. Maddox	Senior Vice President	June 1, 1997 t
	President and Chief Operating Officer, Trading, PG&E National Energy Group, Inc.	April 6, 2000
	President and Chief Executive Officer, PG&E Energy Trading-Gas Corporation	May 12, 1997 t
	President, PennUnion Energy Services, L.L.C.	May 1995 to Ma
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, 199
G. B. Stanley	Senior Vice President, Human Resources	January 1, 199
	Vice President, Human Resources	June 1, 1997 t
	Vice President, Human Resources, Pacific Gas and Electric Company	July 1, 1996 t
B. R. Worthington	Senior Vice President and General Counsel	June 1, 1997 t
	General Counsel	December 18, 1
	Senior Vice President and General Counsel, Pacific Gas and Electric Company	June 1, 1995 t

"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, 2000	Position
G. R. Smith	52	President and Chief Executive Officer
K. M. Harvey	42	Senior Vice President, Chief Financial Offic
R. J. Peters	46	Senior Vice President and General Counsel
J. K. Randolph	56	Senior Vice President and Chief of Utility O
D. D. Richard, Jr.	50	Senior Vice President, Public Affairs
G. M. Rueger	50	Senior Vice President, and Chief Nuclear Off

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	Pe
G. R. Smith	President and Chief Executive Officer	June 1, 1997
	Chief Financial Officer, PG&E Corporation	December 18,
	Senior Vice President and Chief Financial Officer	June 1, 1995
	Vice President and Chief Financial Officer	November 1, 1
K. M. Harvey	Senior Vice President, Chief Financial Officer, and Treasurer	November 1, 2
	Senior Vice President, Chief Financial Officer, Controller, and Treasurer	January 1, 20
	Senior Vice President, Chief Financial Officer, and Treasurer	July 1, 1997
	Vice President and Treasurer	June 1, 1995
R. J. Peters	Senior Vice President and General Counsel	January 1, 19
	Vice President and General Counsel	July 1, 1997
	Chief Counsel, Regulatory	January 1, 19
J. K. Randolph	Senior Vice President and Chief of Utility Operations	April 6, 2000
	Senior Vice President and General Manager, Transmission, Distribution and Customer Service Business Unit	July 1, 1997
	Vice President and General Manager, Power Generation, Business Unit	January 1, 19
	Vice President, Power Generation	November 1, 1
D. D. Richard, Jr.	Senior Vice President, Public Affairs	May 1, 1998 t
	Senior Vice President, Governmental and Regulatory Relations	July 1, 1997

	Senior Vice President, Public Affairs, PG&E Corporation	October 18, 2
	Vice President, Governmental Relations, PG&E Corporation	July 1, 1997
	Vice President, Governmental Relations	January 1, 19
	Executive Vice President and Principal, Morse, Richard, Weisenmiller & Assoc., Inc. (energy, project finance, and environmental consulting)	January 1993
G. M. Rueger	Senior Vice President, Generation and chief Nuclear Officer	April 6, 2000
	Senior Vice President and General Manager, Nuclear Power Generation Business Unit	November 1, 1

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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 89 under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the amended 2000 Annual Report to Shareholders, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report. As of April 9, 2001, there were 132,612 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 20 of the 2000 Annual Report to Shareholders.

Neither Pacific Gas and Electric Company nor PG&E Corporation made any sales of unregistered equity securities during 2000, 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 under the heading "Selected Financial Data" in the amended 2000 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, 2000 was a negative 7.70. Pacific Gas and Electric Company's ratio of earnings to combined fixed charges and preferred stock dividends for the year ended December 31, 2000 was a negative 7.29. The negative ratios of earnings to fixed charges and earnings to combined fixed charges and preferred stock dividends indicates a deficiency in earnings of $5,637 million and $5,673 million respectively. 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 under the heading "Management's Discussion and Analysis" in the amended 2000 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 2000 Annual Report to Shareholders under the heading "Management's Discussion and Analysis--Quantitative and Qualitative Disclosures about Market Risk," and under Notes 1, 4, 8 and 9 of the "Notes to the Consolidated Financial Statements" of the amended 2000 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 in the amended 2000 Annual Report to Shareholders under the following headings for PG&E Corporation: "Statement of Consolidated Operations," "Consolidated Balance Sheets," "Statement of Consolidated Cash Flows," and "Statement of Consolidated Common Stock Equity;" under the following headings for Pacific Gas and Electric Company: "Statement of Consolidated Operations," "Consolidated Balance Sheets," "Statement of Consolidated Cash Flows," and "Statement of Consolidated 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 56 through 58 in Part I of this report. Other information responding to Item 10 is included on pages 3 through 5 under the heading "Item No. 1: Election of Directors of PG&E Corporation and Pacific Gas and Electric Company" and page 40 under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 2001 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 on pages 8 and 9 under the heading "Compensation of Directors" and on pages 31 through 37 under the headings

"Summary Compensation Table," "Option/SAR Grants in 2000," "Aggregated Option/SAR Exercises in 2000 and Year-End Option/SAR Values," "Long-Term Incentive Plan--Awards in 2000," "Retirement Benefits," "Employment Contracts/Arrangements," and "Termination of Employment and Change In Control Provisions" in the Joint Proxy Statement relating to the 2001 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 on pages 10 and 11 under the heading "Security Ownership of Management" and on page 40 under the heading "Principal Shareholders" in the Joint Proxy Statement relating to the 2001 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 on page 9 under the heading "Certain Relationships and Related Transactions" in the Joint Proxy Statement relating to the 2001 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 amended report on Form 10-K:

1. The following consolidated financial statements, supplemental information, and report of independent public accountants contained in the amended 2000 Annual Report to Shareholders, which have been incorporated by reference in this report:

   Statements of Consolidated Operations for the Years Ended December 31, 2000, 1999, and 1998, for each of PG&E Corporation and Pacific Gas and Electric Company.

   Statements of Consolidated Cash Flows for the Years Ended December 31, 2000, 1999, and 1998, for each of PG&E Corporation and Pacific Gas and Electric Company.

   Consolidated Balance Sheets at December 31, 2000 and 1999 for each of PG&E Corporation and Pacific Gas and Electric Company.

   Statement of Consolidated Common Stock Equity for the Years Ended December 31, 2000, 1999, and 1998, for PG&E Corporation.

   Statement of Consolidated Stockholders' Equity for the Years Ended December 31, 2000, 1999, and 1998, 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 64 of this amended report on Form 10-K.

3. Report of Independent Public Accountants (Arthur Andersen LLP) included at page 65 of this amended report on Form 10-K.

4. Report of Independent Public Accountants (Arthur Andersen LLP) included at page 66 of this amended report on Form 10-K.

5. Financial statement schedules (these schedules are the same as the schedules filed with the original filing):

   I-- Condensed Financial Information of Parent for the Years Ended December 31, 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, 2000, 1999 and 1998.

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 By-Laws 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)

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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 By-Laws 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, 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; 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 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 No. 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 Form 10-K filed by PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10)
10.1	Stock Purchase Agreement By and Between PG&E National Energy Group, Inc. and El Paso Field Services Company, dated as of January 27, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1999 (File No. 1-12609), Exhibit No. 10.1)
10.2	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)
*10.3	PG&E Corporation Supplemental Retirement Savings Plan dated as of January 1, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1999 (File No. 1-12609), Exhibit 10.2)
*10.4	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)

*10.5	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)

*10.6	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)
*10.7	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)
*10.8	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)
*10.9	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)
*10.10	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)
*10.10.1	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)
*10.10.2	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)
*10.10.3	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.)
*10.10.4	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)
*10.10.5	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)

*10.10.6 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)

*10.10.7 Letter regarding retention award to James K. Randolph dated February 27, 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 10.10.7)

*10.10.8 Letter regarding retention award to Gregory M. Rueger dated February 27, 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 10.10.8)

*10.10.9 Letter regarding retention award to Kent Harvey dated February 27, 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 10.10.9)

*10.10.10 Letter regarding retention award to Roger J. Peters dated February 27, 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 10.10.10)

*10.10.11 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)

*10.10.12 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)

*10.10.13 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)

*10.10.14 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)

*10.11 Agreement and Release between PG&E Corporation and Thomas W. High dated December 8, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.11)

*10.12 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)

*10.13 Description of Short-Term Incentive Plan for Officers of

	PG&E Corporation and its subsidiaries, effective January 1, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1999 (File No. 1-12609), Exhibit 10.7)
*10.14	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)
*10.15	Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company, effective January 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1998 (File No. 1-12609), Exhibit 10.7)
*10.16	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)
*10.17	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)
*10.18	PG&E Corporation Retirement Plan for Non-Employee Directors, as amended and terminated January 1, 1998 (incorporated by reference to incorporated by reference to PG&E Corporation Form 10-K for the year ended December 31, 1997 (File No. 1-12609), Exhibit No. 10.13)
*10.19	PG&E Corporation Long-Term Incentive Program, as amended February 16, 2000, including the PG&E Corporation Stock Option Plan, Performance Unit Plan, and Non- Employee Director Stock Incentive Plan (incorporated by reference to incorporated by reference to PG&E Corporation Form 10-K for the year ended December 31, 1999, (File No. 1-12609), Exhibit No. 10.12)
*10.20	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)
*10.21	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)

*10.22	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)
*10.23	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)

11. Computation of Earnings Per Common Share (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 11)

12.1 Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000, Exhibit 12.1)

12.2 Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000, Exhibit 12.2)

13. 2000 Amended 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 "Statement of Consolidated Operations," "Consolidated Balance Sheet," "Statement of Consolidated Cash Flows," "Statement of Consolidated Common Stock Equity," financial statements of Pacific Gas and Electric Company entitled "Statement of Consolidated Operations," "Consolidated Balance Sheet," "Statement of Consolidated Cash Flows," "Statement of Consolidated Stockholders' Equity," "Notes to Consolidated Financial Statements" and "Quarterly Consolidated Financial Data (Unaudited)" are included only (Except for those portions that are expressly incorporated herein by reference, such Report to Shareholders is furnished for the information of the Commission and is not deemed to be "filed" herein.)

21. Subsidiaries of the Registrants (incorporated by reference to Form 10-K filed by PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2000, Exhibit 21)

23.1 Independent Auditors' Consent (Deloitte & Touche LLP)

23.2 Consent of Arthur Andersen 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 (incorporated by reference to Form 10-K filed by PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2000, Exhibit 24.1)

24.2 Powers of Attorney (incorporated by reference to Form 10-K filed by PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2000, Exhibit 24.2)

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* 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, 2000 and through the date hereof:

1. October 25, 2000

Item 5. Other Events--

A. Third Quarter 2000 Consolidated Earnings
B. Pacific Gas and Electric Company's Wholesale Power Purchase Costs
C. Transition Cost Recovery
D. Earnings Outlook

2. November 22, 2000

Item 5. Other Events--

A. Valuation and Disposition of Pacific Gas and Electric Company's Hydroelectric Generating Assets
B. Recovery of Wholesale Power Purchase Costs
C. Pacific Gas and Electric Company's Rate Stabilization Plan
D. Federal Energy Regulatory Commission Order
E. Pacific Gas and Electric Company's Federal Complaint

3. December 8, 2000

Item 5. Other Events--

A. Valuation and Disposition of Pacific Gas and Electric Company's Hydroelectric Generating Assets
B. Pacific Gas and Electric Company's Rate Stabilization Plan
C. CPUC's Post-transition Period Ratemaking Decision

4. December 18, 2000

Item 5. Other Events--

A. Recent Regulatory Actions Addressing the California Energy Market
B. Pacific Gas and Electric Company's Wholesale Power Purchase Costs
C. Liquidity and Financial Impacts

5. December 22, 2000

Item 5. Other Events--

A. California Energy Crisis
B. PG&E Corporation Shareholder Rights Plan

6. December 29, 2000

Item 5. Other Events--California Energy Crisis

7. January 4, 2001

Item 5. Other Events--California Energy Crisis

8. January 5, 2001

Item 5. Other Events--

California Public Utilities Commission Decision Issued

9. January 10, 2001

Item 5. Other Events--

A. Current Financial Condition
B. Impending Natural Gas Shortage
C. ISO's Requested Tariff Amendment to Creditworthiness Standards

10. January 10, 2001

Item 5. Other Events--Suspension of PG&E Corporation and Pacific Gas and Electric Company Dividends

11. January 17, 2001

Item 5. Other Events--

A. Ratings Downgrades
B. Liquidity Impacts and Financial Condition

12. February 1, 2001

Item 5. Other Events--

A. Wholesale Power Payments
B. Liquidity Impacts and Financial Condition
C. Federal Lawsuit
D. Rate Stabilization Plan Proceeding
E. Consulting Report
F. CPUC Emergency Action

13. February 14, 2001

Item 5. Other Events--

A. Assembly Bill 1X

B. Liquidity Impacts and Financial Condition
C. Federal Lawsuit

14. February 28, 2001

Item 5. Other Events--

A. Recent Regulatory Action
B. Liquidity
C. Wilson vs. PG&E Corporation and Pacific Gas and Electric Company

15. March 2, 2001--Filed by PG&E Corporation only

Item 5. Other Events--PG&E Corporation debt restructure

16. March 9, 2001

Item 5. Other Events

A. Recent Regulatory Action
B. 2001 Cost of Capital Proceeding

17. March 16, 2001

Item 5. Other Events--Liquidity and Financial Condition

18. March 23, 2001

Item 5. Other Events

A. Recent Legislative and Regulatory Actions
B. Accounting Treatment
C. Bank Forbearance Agreement

19. March 30, 2001

Item 5. Other Events

A. Recent Regulatory Actions
B. Accounting Treatment
C. Liquidity and Financial Condition

20. April 6, 2001 (as amended)--Filed by PG&E Corporation only

Item 5. Other Events--Pacific Gas and Electric Company Bankruptcy

21. April 6, 2001 (as amended)--Filed by Pacific Gas and Electric Company only

Item 3. Other Events--Bankruptcy or Receivership.

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(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 Amendment No. 1 to the their Annual Report on Form 10-K/A for the year ended December 31, 2000 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)	PACIFIC GAS AND ELECTRIC COMPANY (Registrant)
By /s/ Gary P. Encinas	By /s/ Gary P. Encinas
(Gary P. Encinas, Attorney-in-Fact)	(Gary P. Encinas, Attorney-in-Fact)

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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 and subsidiaries as of and for the years ended December 31, 2000 and 1999 and have issued our report thereon dated April 6, 2001, February 26, 2002 as to Note 17, which report includes explanatory paragraphs concerning the ability of Pacific Gas and Electric Company to continue as a going concern and the revision of PG&E Corporation's 1999 and 2000 financial statements to consolidate the assets and liabilities associated with certain leases; such consolidated financial statements are included in your 2000 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, listed in Item 14(a)5. 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
April 6, 2001, February 26, 2002 as to Note 17

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REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

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

We have audited in accordance with generally accepted auditing standards, the consolidated financial statements for the year ended December 31, 1998 included in the PG&E Corporation and Pacific Gas and Electric Company Annual Report to Shareholders incorporated by reference in this Form 10-K, and have issued our report thereon dated February 8, 1999. Our audits were made for the purpose of forming an opinion on the basic consolidated financial statements taken as a whole. The Condensed Financial Information of Parent for the Year Ended December 31, 1998 and the Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Year Ended December 31, 1998 are the responsibility of the management of PG&E Corporation and of Pacific Gas and Electric Company. These schedules are for purposes of complying with the Securities and Exchange Commission's rules and are not part of the basic consolidated financial statements. These schedules have been subjected to the auditing procedures applied in the audits of the basic consolidated financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the basic consolidated financial statements taken as a whole.

ARTHUR ANDERSEN LLP

San Francisco, California
February 8, 1999

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

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

We have audited the accompanying statements of consolidated operations, cash flows, and common stock equity of PG&E Corporation (a California corporation) and subsidiaries and the statements of consolidated operations, cash flows, and stockholders' equity of Pacific Gas and Electric Company (a California corporation) and subsidiaries for the year ended December 31, 1998. These financial statements are the responsibility of the management of PG&E Corporation and 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 generally accepted auditing standards. Those standards require that we plan and perform the audit 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, the financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of PG&E Corporation and subsidiaries and Pacific Gas and Electric and subsidiaries for the year ended December 31, 1998, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP

San Francisco, California
February 8, 1999

SCHEDULE I--CONDENSED FINANCIAL INFORMATION OF PARENT

CONDENSED BALANCE SHEETS

	December 31, 2000	December 31, 1999
	(in millions)	
Assets:		
Cash and cash equivalents	$ 351	$ 155
Advances to affiliates	295	299
Note receivable from subsidiary	308	--
Other current assets	6	--
Total current assets	960	454
Equipment	15	16
Accumulated depreciation	(6)	(3)
Net equipment	9	13
Investments in subsidiaries	3,439	6,931
Other investments	64	52
Deferred income taxes	--	396
Other deferred charges	1	--
Total Assets	$ 4,473	$ 7,846
Liabilities and Stockholders' Equity:		
Current Liabilities:		
Short-term borrowings	$ 931	$ 526
Accounts payable--related parties	59	76
Accounts payable--trade	13	10
Note payable to subsidiary	75	--
Accrued taxes	108	117
Dividends payable	109	110
Other	25	112
Total current liabilities	1,320	951
Noncurrent Liabilities:		
Deferred income taxes	9	--
Other	10	5
Total noncurrent liabilities	19	5
Stockholders' Equity:		
Common stock	5,971	5,906
Common stock held by subsidiary	(690)	(690)
Reinvested earnings	(2,147)	1,674
Total stockholders' equity	3,134	6,890
Total Liabilities and Stockholders' Equity	$ 4,473	$ 7,846

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

CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 2000, 1999, and 1998

	2000	1999	1998
	(in millions except per share amounts)		
Administrative service revenue	$ 111	$ 82	$ 64
Equity in earnings (losses) of subsidiaries	(3,316)	853	736
Operating expenses	(111)	(86)	(63
Loss on assets held for sale	--	(1,275)	--
Interest expense	(27)	(30)	(52
Other income	22	16	5
Income (Loss) Before Income Taxes	(3,321)	(440)	690
Less: Income Taxes	(4)	(447)	(83
Income (Loss) from continuing operations	(3,317)	7	773
Discontinued operations	(40)	(98)	(52
Cumulative effect of a change in an accounting principle	--	12	--
Net income (loss) before intercompany elimination	(3,357)	(79)	721
Eliminations of intercompany (profit) loss	(7)	6	(2
Net income (loss)	$(3,364)	$ (73)	$ 719
Weighted Average Common Shares Outstanding, Basic and Diluted ...	362	368	382
Earnings (Loss) Per Common Share, Basic and Diluted	$ (9.29)	$ (0.20)	$ 1.88

CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2000, 1999, and 1998

Cash Flows From Operating Activities:
Net income (loss) ....
Adjustments to reconcile net income (loss) to net cash provided by operating activities:
   Equity in earnings of subsidiaries ....
   Deferred taxes ....
   Loss on assets held for sale ....
   Distributions from consolidated subsidiaries ....
   Other-net ....

Net cash provided by operating activities ....
Cash Flows From Investing Activities:
   Capital expenditures ....

Investment in subsidiaries	
Loans to subsidiaries	
Return of capital by Utility (share repurchases)	
Other-net	
Net cash provided (used) by investing activities	
Cash Flows From Financing Activities:	
Common stock issued	
Common stock repurchased	
Loans from subsidiary	
Short-term debt issued (redeemed)-net	
Dividends paid	
Other-net	
Net cash provided (used) by financing activities	
Net Change in Cash & Cash Equivalents	
Cash & Cash Equivalents at January 1	
Cash & Cash Equivalents at December 31	

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PG&E CORPORATION

SCHEDULE II -- CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2000, 1999, and 1998

Column A	Column B	Column C	
		Additions	
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts
			(in thousands)
Valuation and qualifying accounts deducted from assets:			
2000:			
Allowance for uncollectible accounts (2)	$ 65,128	$ 47,980	$ 1,484
Provision for loss on generation-related regulatory assets and undercollected purchased power costs (3)	$ --	$6,939,000	$ --
1999:			
Allowance for uncollectible accounts (2)	$ 58,577	$ 25,243	$ (183)
1998:			
Allowance for uncollectible accounts (2)	$ 72,912	$ 10,978	$ (2,893)

(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."

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PACIFIC GAS AND ELECTRIC COMPANY

SCHEDULE II -- CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2000, 1999, and 1998

Column A	Column B	Column C	
		Additions	
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts
			(in thousa
Valuation and qualifying accounts deducted from assets:			
2000:			
Allowance for uncollectible accounts (2)	$ 46,421	$ 19,008	$ 1,484
Provision for loss on generation-related regulatory assets and undercollected purchased power costs (3)	$ --	$6,939,000	$ --
1999:			
Allowance for uncollectible accounts (2)	$ 47,347	$ 17,011	$ 44
1998:			
Allowance for uncollectible accounts (2)	$ 59,608	$ 10,007	$ 152

(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."

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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 By-Laws 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 By-Laws 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, 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; 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 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 No. 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 Form 10-K filed by PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10)

10.1	Stock Purchase Agreement By and Between PG&E National Energy Group, Inc. and El Paso Field Services Company, dated as of January 27, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1999 (File No. 1-12609), Exhibit No. 10.1)
10.2	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)
*10.3	PG&E Corporation Supplemental Retirement Savings Plan dated as of January 1, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1999 (File No. 1-12609), Exhibit 10.2)
*10.4	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)
*10.5	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)
*10.6	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)
*10.7	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)
*10.8	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)
*10.9	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)

*10.10	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)
*10.10.1	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)
*10.10.2	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)
*10.10.3	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.)
*10.10.4	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)
*10.10.5	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)
*10.10.6	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)
*10.10.7	Letter regarding retention award to James K. Randolph dated February 27, 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 10.10.7)
*10.10.8	Letter regarding retention award to Gregory M. Rueger dated February 27, 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 10.10.8)
*10.10.9	Letter regarding retention award to Kent Harvey dated February 27, 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 10.10.9)
*10.10.10	Letter regarding retention award to Roger J. Peters dated February 27, 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 10.10.10)

*10.10.11	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)
*10.10.12	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)
*10.10.13	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)
*10.10.14	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)
*10.11	Agreement and Release between PG&E Corporation and Thomas W. High dated December 8, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.11)
*10.12	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)
*10.13	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1999 (File No. 1-12609), Exhibit 10.7)
*10.14	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)
*10.15	Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company, effective January 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1998 (File No. 1-12609), Exhibit 10.7)
*10.16	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)
*10.17	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)
*10.18	PG&E Corporation Retirement Plan for Non-Employee

	Directors, as amended and terminated January 1, 1998 (incorporated by reference to incorporated by reference to PG&E Corporation Form 10-K for the year ended December 31, 1997 (File No. 1-12609), Exhibit No. 10.13)
*10.19	PG&E Corporation Long-Term Incentive Program, as amended February 16, 2000, including the PG&E Corporation Stock Option Plan, Performance Unit Plan, and Non- Employee Director Stock Incentive Plan (incorporated by reference to incorporated by reference to PG&E Corporation Form 10-K for the year ended December 31, 1999, (File No. 1-12609), Exhibit No. 10.12)
*10.20	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)
*10.21	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)
*10.22	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)
*10.23	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)
11.	Computation of Earnings Per Common Share (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 11)
12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000, Exhibit 12.1)
12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000, Exhibit 12.2)
13.	2000 Amended 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 "Statement of Consolidated Operations," "Consolidated Balance Sheet," "Statement of Consolidated Cash Flows," "Statement of Consolidated Common Stock Equity," financial statements of Pacific Gas and Electric Company entitled "Statement of Consolidated

Operations," "Consolidated Balance Sheet," "Statement of Consolidated Cash Flows," "Statement of Consolidated Stockholders' Equity," "Notes to Consolidated Financial Statements" and "Quarterly Consolidated Financial Data (Unaudited)" are included only (Except for those portions that are expressly incorporated herein by reference, such Report to Shareholders is furnished for the information of the Commission and is not deemed to be "filed" herein.)

21.	Subsidiaries of the Registrants (incorporated by reference to Form 10-K filed by PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2000, Exhibit 21)
23.1	Independent Auditors' Consent (Deloitte & Touche LLP)
23.2	Consent of Arthur Andersen 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 (incorporated by reference to Form 10-K filed by PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2000, Exhibit 24.1)
24.2	Powers of Attorney (incorporated by reference to Form 10-K filed by PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2000, Exhibit 24.2)

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* 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.