Omaha Public Power District
444 South 16th Street Mall
Omaha, Nebraska 68102-2247
402/636-2000

March 23, 1993
LIC-93-0098

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Station P1-137
Washington, DC 20555

REFERENCE: Docket No. 50-285

Gentlemen:

SUBJECT: 1992 Annual Financial Report

In accordance with 10 CFR 50.71(b), enclosed is one copy of Omaha Public Power District's 1992 Annual Financial Report.

If you should have any questions, please contact me.

Sincerely,

W. G. Gates

W. G. Gates
Vice President

WGG/mle

Enclosure

c: LeBoeuf, Lamb, Leiby & MacRae (w/o Enclosure)
J. L. Milhoan, NRC Regional Administrator, Region IV (w/o Enclosure)
S. D. Bloom, NRC Project Manager (w/o Enclosure)
R. P. Mullikin, NRC Senior Resident Inspector (w/o Enclosure)

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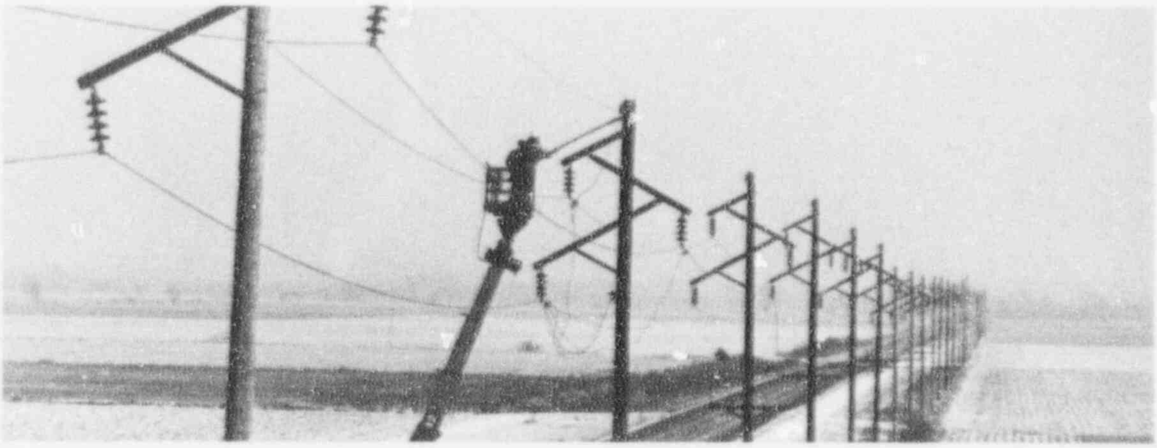

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O P P D

A N N U A L

R E P O R T

OMAHA PUBLIC POWER DISTRICT

EXECUTIVE OFFICES
Energy Plaza
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

TRUSTEE
The First National Bank of Chicago
Chicago, Illinois

PAYING AGENTS
First Chicago Trust Company of New York
New York, New York

The First National Bank of Chicago
Chicago, Illinois

Norwest Bank Nebraska, N.A.
Omaha, Nebraska

MINIBOND ADMINISTRATION
Omaha Public Power District
Treasury Analysis Department

GENERAL COUNSEL
Fraser, Stryker, Vaughn, Meusey,
Olson, Boyer & Bloch, P.C.
Omaha, Nebraska

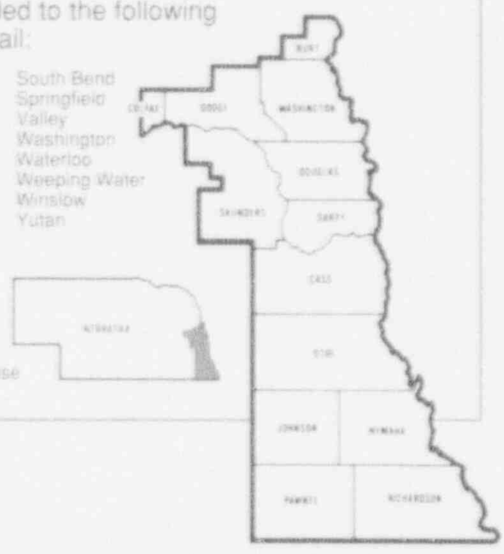
CONTENTS

OPPD SERVICE AREA: 5,000 SQUARE MILES

OPPD serves 604,000 people in all or part of 13 counties in eastern Nebraska. Electric service is provided to the following 49 incorporated communities at retail:

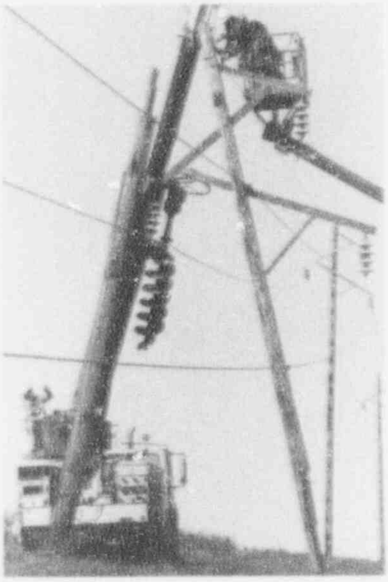
Alvo	Colon	Manley	South Bend
Arlington	Cook	Mead	Springfield
Ashland	Eagle	Memphis	Valley
Avoca	Elkhorn	Morse Bluff	Washington
Bellevue	Elmwood	Murdock	Waterloo
Bennington	Fort Calhoun	Nickerson	Weeping Water
Blair	Gretna	North Bend	Winslow
Boys Town	Herman	Omaha	Yutan
Burr	Hooper	Papillion	
Carter Lake (Iowa)	Ithaca	Peru	
Cedar Bluffs	Kennard	Ralston	
Cedar Creek	LaVista	Rogers	
Ceresco	Leshara	Rulo	
	Louisville	Salem	

OPPD also serves Elk Creek, Greenwood, Syracuse and Tecumseh at wholesale.



OPERATING REVENUES
Operating revenues for 1992 were $373,113,000, a decrease of $8,846,000, or 2.3%, from 1991 operating revenues of $381,959,000.

OPERATION AND MAINTENANCE EXPENSES
Operation and maintenance expenses for 1992 were $226,063,000, a decrease of $11,167,000, or 4.7%, from 1991 operation and maintenance expenses of $237,230,000.



While weather didn't severely affect OPPD's transmission and distribution system in 1992, brief winds did topple some poles in OPPD's South Subdivision last fall.

NET OPERATING REVENUES
Net operating revenues, before depreciation and decommissioning, were $133,126,000, an increase of $2,756,000, or 2.1%, from 1991 net operating revenues of $130,370,000.

NET EARNINGS REINVESTED IN THE BUSINESS
Net earnings reinvested in the business totalled $30,255,000, a decrease of $4,954,000, or 14.1%, from 1991 net earnings reinvested in the business of $35,209,000.

GENERAL BUSINESS SALES
General business sales to District customers were 6,452,515,000 kilowatt-hours in 1992, a decrease of 253,003,000, or 3.8%, from 1991 sales of 6,705,518,000 kilowatt-hours.

AVERAGE NUMBER OF CUSTOMERS
The District served an average total of 255,960 customers in 1992, an increase of 3,533, or 1.4%, from the 1991 average total of 252,427 customers.

AVERAGE RESIDENTIAL USE
Average annual use per residential customer in 1992 was 9,546 kilowatt-hours, a decrease of 1,445, or 13.1%, from the 1991 average of 10,991 kilowatt-hours.

AVERAGE RESIDENTIAL COST
The District's residential customers paid an average of 6.64¢ per kilowatt-hour during 1992 compared to 3.39¢ per kilowatt-hour in 1946, OPPD's initial year of operation.

1992 NET CONSTRUCTION EXPENDITURES
Expansion and improvement of system facilities during 1992 required net construction expenditures of $97,558,000.

OPPD employees replace rollers on the coal belt at Nebraska City Station, OPPD's lowest-cost power producer.

CHAIRMAN'S REPORT

Frank J. Wear
Chairman of the Board
Omaha Public Power District

President,
Wear Company, and
President, Wear Construction

All things considered, 1992 was an extraordinary year for the Omaha Public Power District.

Weather was at the heart of it. We began with a mild winter, continued with a mild spring, and then experienced an unusually cool summer. Only in the last several months did we approach normal weather conditions.

This unusual weather pattern resulted in markedly reduced electricity sales and revenues. We had just under 6.6 billion in kilowatt-hour sales, approximately 4.8 percent below budget. Similarly, our revenues were $373.1 million, about 8.9 percent under the forecast. To offset these reductions, we reduced costs across the board. As a result, year-end capital costs were $18.4 million under budget, and operations and maintenance expenditures were $27.7 million down.

The bottom line for all of this is that net earnings were $30.3 million, about $11.3 million less than forecast, but quite good, nevertheless. The return on equity was 4.8 percent. Our financial position remained sound.

A moderate rate increase of 3.7 percent was effective with January 1992 billings, so the cost of electricity for our customers was slightly higher. Residential customers, however, still paid an average of only 6.64 cents per kilowatt-hour, well under the national average. When all retail classes of customers are considered, the average price per kilowatt-hour was 5.65 cents, compared to 5.57 cents in 1991.

OPPD also took advantage of the attractive low interest rates that prevailed in the municipal bond market in 1992. In April, the sale of $150 million in Electric System Revenue Bonds was authorized and subsequently completed. Proceeds were used to redeem $28 million of bonds issued in 1966, 1968 and 1969, to pay off $100 million in short-term commercial paper, and to provide funds for capital improvements.

Again, because of attractive interest rates, we undertook another bond issue in the fall. Proceeds from this $167.3 million issue were used to advance refund $97.8 million of 1989 Series A Bonds and to provide funds for OPPD's 1993-1994 construction program. In a separate transaction in November, the District defeased to maturity $63.8 million of 1986 Series A Bonds, using funds from operations. All told, the refinancing efforts in 1992 resulted in present value savings of $16.3 million.

In addition, we introduced an innovative program in July to bring the concept of public ownership closer to our customer-owners and other Nebraska residents. The Board authorized the sale to Nebraska residents of up to $10 million in OPPD Minibonds in minimum denominations of $200 and $500. The issue quickly sold out. The funds are being used to improve and extend OPPD's electrical system.

We're counting on a return to more normal weather patterns in 1993, which should mean an increase in total energy sales of 7.4 percent and a 13.5 percent increase in operating revenues to $423.6 million. Capital expenditures are expected to total $118.4 million with major expenditures earmarked for construction of a new combustion turbine and for major refurbishment and expansion at our North Omaha Power Station.

No rate increases are contemplated during the year. We are forecasting net earnings of $40.9 million and a 6.2 percent return on equity.

Directors Keith B. Edquist, John K. Green and Frederick J. Ulrich won reelection in 1992. I look forward to working with them again and with colleagues Dennis D. Jorgensen, Eugene T. Mahoney, Michael J. O'Hara and Gene P. Spence as we cope with the challenges that face us in 1993.

These men worked extremely hard for this utility in 1992, as did our strong management team and competent work force. All are committed to excellence, which will enable OPPD to continue providing reliable electric energy and energy services at the lowest reasonable cost.

Frank J. Wear

Frank J. Wear
Chairman of the Board

BOARD OF DIRECTORS

Michael J. O'Hara, Ph.D.
Vice Chairman

Attorney at Law
Associate Professor
University of Nebraska
at Omaha

John K. Green
Treasurer

Attorney at Law

Frederick J. Ulrich
Secretary

Farmer/Cattle Feeder

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Board Member

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Husker-Hawkeye
Distributing Co., Inc.

Dennis D. Jorgensen
Board Member

President,
Summit Limited

Eugene T. Mahoney
Board Member

Executive Director,
Omaha Zoo Foundation

Gene P. Spence
Board Member

President,
Westmark Financial Corp.

PRESIDENT'S REPORT

Fred M. Petersen
President
Chief Executive Officer

At OPPD, we don't believe that what was good enough for our customers yesterday will be good enough for them today or good enough tomorrow.

Quality customer service at an affordable price is our top priority. We operate with the belief that if we constantly look for better ways of providing that service, we'll find them.

So, while we're proud of our past accomplishments, we view them primarily as building blocks toward our ultimate goal of being the best publicly owned utility in the country. There were a number of such building blocks in 1992.

The achievements at our coal-fired Nebraska City Station provide one example of the continuing improvement for which we work in all areas of our operation.

Nebraska City Station was the third least-expensive steam-electric power generator in the country in 1990, producing electricity at an average cost of $11.06 per net megawatt-hour. However, the many OPPD personnel associated with that operation continued their efforts to increase efficiency and economy, and achieved even greater success. Industry statistics published late last year showed that Nebraska City Station was the second least-expensive steam-electric power producer in the country in 1991, with an average cost of just $10.21 per net megawatt-hour.

There was also good news at Fort Calhoun Station, OPPD's nuclear power generating facility. The plant operated below budget in 1992, despite two unanticipated outages last summer, both caused by a malfunctioning valve.

The Nuclear Regulatory Commission had high praise for the response of OPPD personnel to the events, concluding that plant and public safety was maintained at all times. Further, OPPD personnel discovered previously unknown information about valve performance characteristics that has resulted in even greater safety at Fort Calhoun Station and in the nuclear industry, in general.

Meanwhile, ongoing modernization efforts helped North Omaha Station, OPPD's oldest coal-fired generating facility, generate nearly 2.4 billion kilowatt-hours of electricity in 1992. That was about 31 percent of OPPD's total 1992 generation, and it was the highest production there in a decade.

Looking toward the future, OPPD continued development work for a combustion turbine which will be needed to supply peaking power by the summer of 1995. Demand-side management (DSM) programs also gained momentum during the year.

DSM is intended to help control future demand for electricity by helping customers reshape their consumption patterns. An important strategy for achieving that is to promote the use of energy-efficient space-conditioning equipment. In 1992, under the Residential Energy Conservation Program, customers installed more than 1,300 high-efficiency heat pumps and air conditioners which are estimated to be twice as efficient as the equipment they replaced. This and other important DSM programs will intensify in 1993.

Meeting existing and future power supply needs requires solid power delivery systems. OPPD efforts in this area included completion of a new transmission line, two new substations in the southwest metropolitan Omaha area, and continuation of an aggressive power line inspection program. Using infrared imaging equipment, OPPD inspectors identified almost 120 potential equipment problems. Repairs were made preventing outages to as many as 40,000 customers.

Overall, the daily activities undertaken to make OPPD a better utility in the present and future are too numerous to list. But the bottom line remains this — the employees of OPPD continually strive to do better tomorrow than they did yesterday. It's a commitment to service that has produced excellent results for OPPD customers in the past, and it will continue to do so in 1993 and beyond.

Fred M. Petersen

Fred M. Petersen
President

VICE PRESIDENTS

Eldon C. Pape
Executive Vice President – Chief Financial and Planning Officer

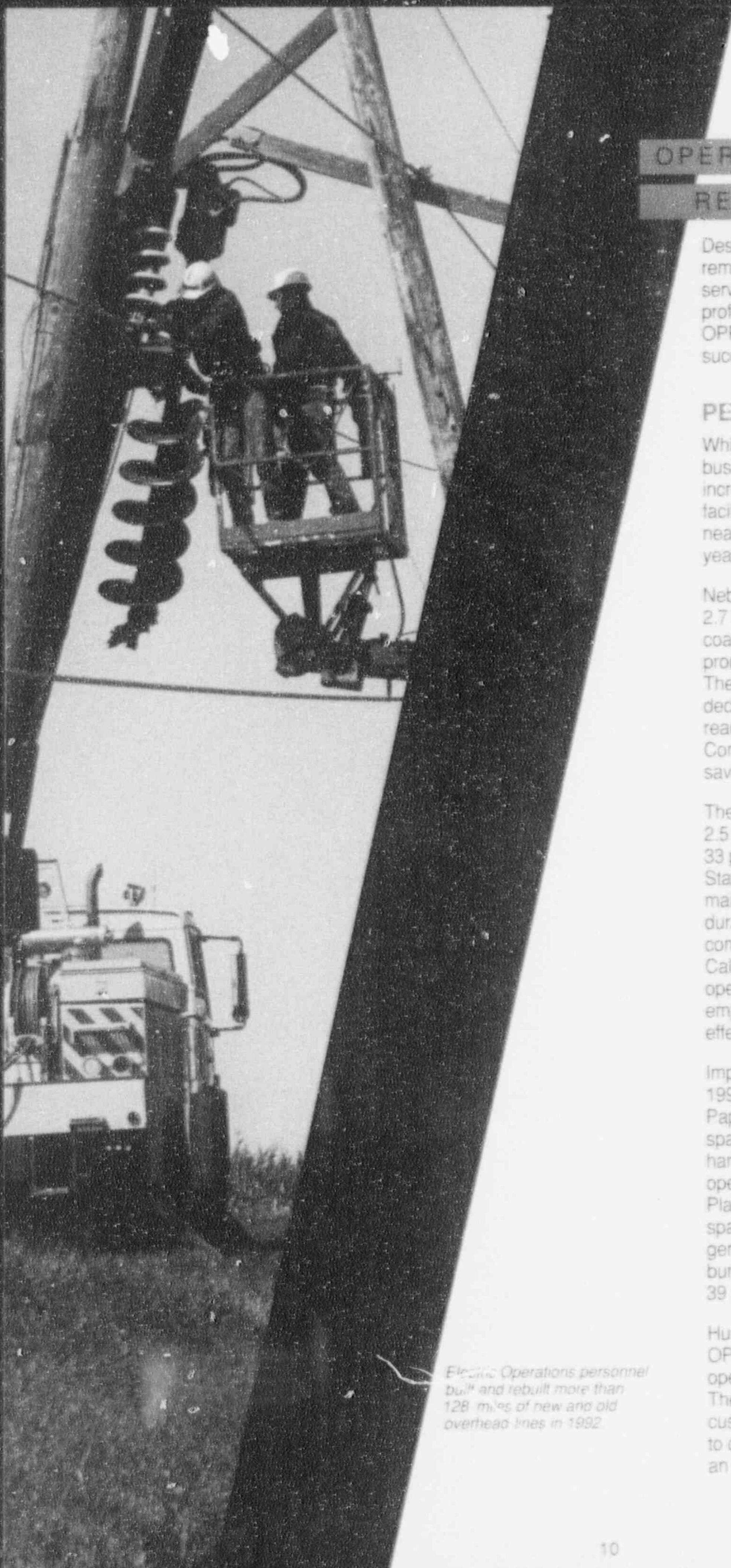
William C. Jones
Senior Vice President

William D. Dermyer
Vice President

Kenneth S. Fielding
Vice President

W. Gary Gates
Vice President

Dayton D. Wittke, Ph.D.
Vice President



Electric Operations personnel built and rebuilt more than 128 miles of new and old overhead lines in 1992.

OPERATIONS REVIEW

Despite many financial challenges in 1992, OPPD remained dedicated to providing reliable, quality service. Employees displayed their commitment and professionalism by reducing overall costs, thus enabling OPPD to retain its solid financial position and have a successful year.

PERFORMING EFFICIENTLY

While abnormally mild summer weather cut general business sales, it did not dampen OPPD's efforts to increase efficiency and performance at its operating facilities. OPPD's power generating plants produced nearly 7.7 billion kilowatt-hours of electricity during the year.

Nebraska City Station accounted for more than 2.7 billion of those kilowatt-hours. The 585,000-kilowatt coal-fired facility is not only OPPD's lowest-cost power producer, but also one of the nation's most economical. The already low cost of producing electricity there may decline further, thanks to a new coal price agreement reached by OPPD and the Exxon Coal and Minerals Company in 1992. Under the agreement, OPPD will save $2.4 million over the next three years.

The Fort Calhoun Station produced more than 2.5 billion kilowatt-hours of electricity, or just under 33 percent of OPPD's total generation. Fort Calhoun Station also completed its annual refueling and maintenance outage in 92 days — the shortest duration for an outage since 1978 — and it was completed within budget. The top priority at Fort Calhoun Station continues to be the safe, efficient operation of the plant, and there is also strong emphasis being given to plant reliability and cost effectiveness.

Improvements were made at other OPPD facilities in 1992 to prepare them for growing workloads. The Papillion and Irvington centers acquired additional space, as well as new emergency generators to handle increased load and ensure continued operations, particularly during widespread outages. Plans were developed to renovate and add needed space at the North Omaha Power Station, which generated over 2 billion kilowatt-hours of electricity and burned 1,615,759 tons of coal, the most ever in its 39 years of operation.

Hundreds of citizens and community leaders in OPPD's South Subdivision helped celebrate the opening of the new Syracuse Service Center in June. The 35,000-square-foot center is enhancing service for customers in and around that area by allowing OPPD to consolidate a variety of functions under one roof. It's an important addition that will provide many years of

reliable service for the 3,000-square-mile area, which accounts for 60 percent of the territory served by OPPD.

DELIVERING POWER

Transmission system performance was strengthened last year with the energizing of the Missouri-Iowa-Nebraska Transmission (MINT) line. The 105-mile 345-kv transmission line stretches from Cooper Nuclear Station near Brownville, Neb., to the town of Fairport in northwest Missouri, and then to St. Joseph, Mo. This new interconnection has improved reliability for OPPD and the other six participating utilities, as well as enhanced the ability to exchange power and energy.

Even though weather did not severely affect OPPD's transmission and distribution systems last year, OPPD kept working on ways to reduce outage time. Approximately 8,000 faulted-circuit indicators were installed on residential distribution transformers. These indicators enable OPPD crews to locate underground power line problems more quickly. In addition, the company invested in a new mobile substation. This 161-kilovolt - 13.8-kilovolt unit can be transported to trouble areas within a short period of time, greatly reducing the duration of a power outage.

Other general maintenance and improvements to OPPD power delivery systems last year included the following:

- Building and rebuilding 128.5 miles of new and old overhead lines
- Overhauling 722 transformers
- Installing underground service cable to 1,000 new homes
- Replacing 15 miles of underground primary cable (This was accomplished by using a boring technique to minimize customer disruption.)

PLANNING ENERGY

OPPD is not only committed to providing electricity today, but also in the future. To help ensure that customers of tomorrow have reliable, dependable electricity at a reasonable cost, OPPD launched several demand-side management programs in 1992.

To help guide OPPD's 300 largest customers with their energy planning, OPPD assigned account executives to specialize in the various business areas. These account executives work closely with their customers and are helping them improve their operations through the most efficient use of energy.

To promote energy efficiency among OPPD's larger commercial and industrial customers, a new incentive rate was established for customers agreeing to curtail their electrical loads during peak periods of electricity demand.

An innovative demand-side management program involved the promotion of high-efficiency compact fluorescent bulbs. OPPD sold 23,000 RightLights, which use 75 percent less energy than regular incandescent bulbs, to commercial customers. The acceptance of the program was high, as was the energy savings. The program results provided information to OPPD on lighting programs and helped give customers experience with this lighting technology.

In another voluntary form of demand-side management, more than 75,000 credits were earned on customers' electric bills last summer through the Energy Management Credit Program. Customers qualified for the credit by using more than 100 kilowatt-hours but less than 401 kilowatt-hours during any of the four summer months, June, July, August and September.

PROVIDING MORE

OPPD takes pride in providing more than electricity. Service and convenience for all customers have always been a priority, which is why OPPD has begun offering bill information in Braille for the visually impaired. OPPD also has two special telephone lines for use by the hearing impaired.

Other OPPD programs proved beneficial to many customers, as well. For example, 60,000 customers who participated in the Level Payment Plan enjoyed the convenience of predictable energy bills throughout the plan year and then received record refunds last fall. The refunds accumulated primarily because of the mild summer weather. Also, in 1990 and continuing throughout 1991 and 1992, OPPD worked hard to lower production costs, and those savings were credited to customers on their monthly bills through the Fuel and Production Cost Adjustment.

When a rural church building was moved to a new location last summer, OPPD crews raised overhead power lines to allow safe passage.

OPERATIONS REVIEW

These lower costs were among the reasons that OPPD customers continued to pay less for their electricity than the national average. Based on late-year figures compiled by the Edison Electric Institute, OPPD residential customers paid an average 19.5 percent less for electricity than their counterparts across the nation during the 12-month period ending September 30, 1992.

Both urban and rural areas received a financial boost from OPPD when the utility made its annual in-lieu-of-tax payments last April. More than $13.3 million was paid to 11 Nebraska counties in 1992.

Computer-aided drafting allows employees to plan projects more quickly and contributes to OPPD's efforts to provide dependable, affordable electricity.

Committed to the community and the environment, OPPD launched another year of its Tree Promotion Program. Through the program, which was started four years ago, a total of 12,458 trees and shrubs were planted last year for community betterment projects.

OPPD continued working with several agencies to develop high-volume uses for fly ash, a coal combustion by-product. Improvement projects for Interstate 480 and several streets in the OPPD service territory are utilizing a mix of fly ash and portland cement in concrete. OPPD hopes to reduce the amount of fly ash placed in landfills by promoting new uses for this coal by-product.

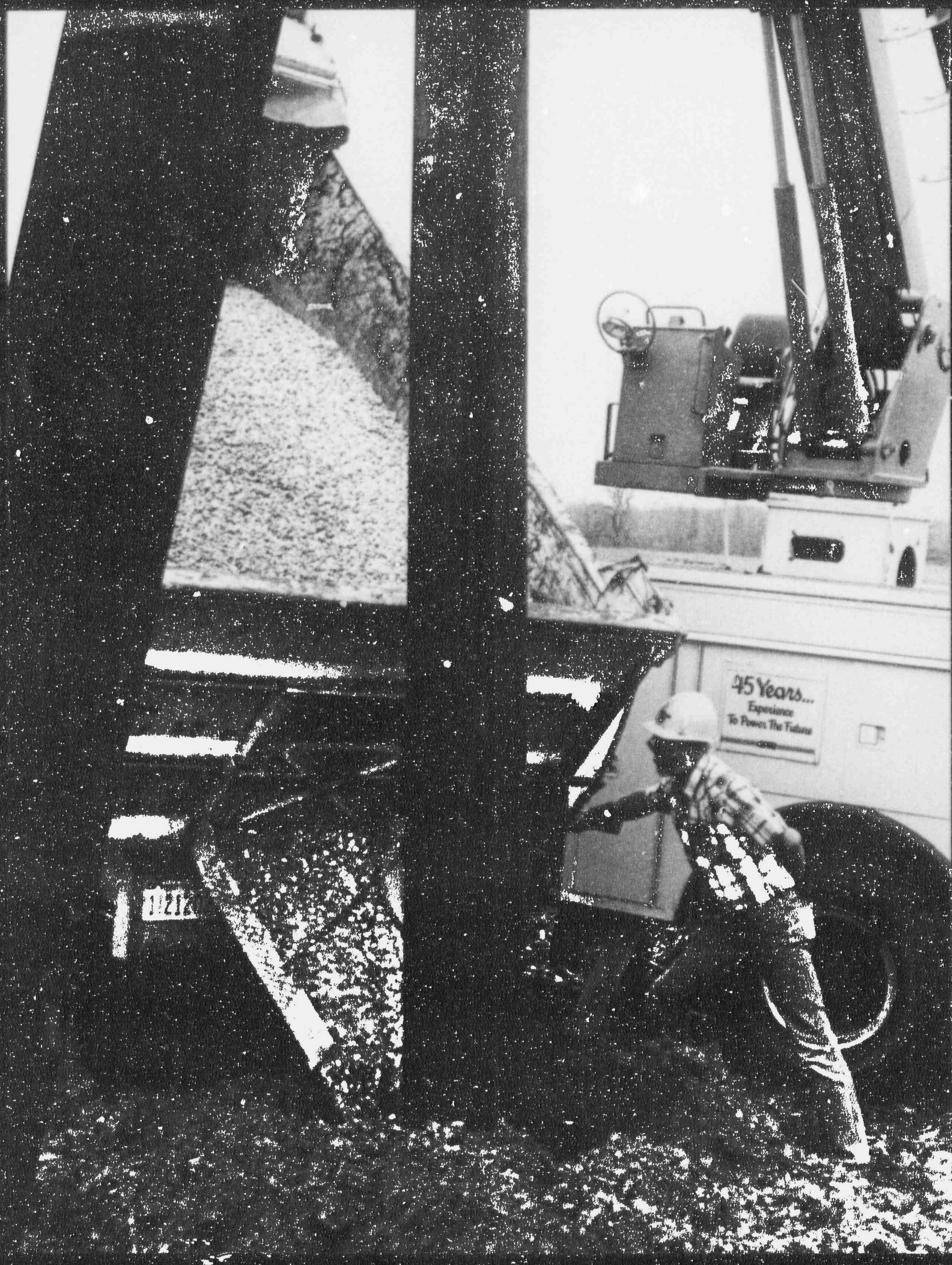
The company also completed its portion of a national study to measure residential electromagnetic fields. The study is being conducted by the Electric Power Research Institute of which OPPD is a member. Data from the study will be used to characterize the relationship between magnetic fields in the home and nearby transmission and distribution lines. A dozen OPPD employees volunteered to take part in the study.

Thanks to the generosity of OPPD customers, employees and area businesses, more than $83,000 was contributed to the Energy Assistance Program (EAP) in 1992. Through the EAP, disadvantaged families are helped with energy-related emergency needs. More than $366,000 has been contributed to the program since its inception.

OPPD's commitment to its community involves much more than its basic task of providing electricity at an affordable cost. Although challenged by the unexpected events of 1992, the hard work and dedication of OPPD employees enabled the utility to fulfill this total commitment in 1992 and renew it for the future.

More than 12,000 trees and shrubs were planted last year as part of OPPD's Tree Promotion Program.

Next Page: OPPD line crews installed several power poles with rectangular shafts last year. It was the first-ever use of such poles by OPPD.


45 Years...
Experience
To Power The Future

OPPD personnel sign Minibonds, which were sold last year to more that 1,600 Nebraska residents. The small-denomination Minibonds allowed residents to take advantage of a tax-exempt investment.

FINANCING

In December 1946, Omaha Public Power District funded the purchase of The Nebraska Power Company with a bank loan for $42,000,000. Revenue bonds were issued in February 1947 to pay off this loan. Since then, $1,905,230,000 of additional bonds have been sold.

In March 1992, the District issued $50,000,000 of tax exempt commercial paper (TECP). In May 1992, the 1992 Series A Bonds totalling $150,000,000 were sold. Proceeds were used primarily for calling the outstanding $28,000,000 original bonds, redeeming $100,000,000 of TECP and for capital improvements. In October 1992, the 1992 Series B Bonds totalling $167,300,000 were sold. Proceeds were used primarily for advance refunding the remaining $97,800,000 1989 Series A Bonds and for capital improvements. In October 1992, the District sold $10,000,000 of subordinated debt Minibonds. Proceeds were used for improvements and extensions to the electric delivery system.

In November 1992, the District defeased to maturity the remaining $63,820,000 1986 Series A Bonds using funds on hand. The District also had scheduled retirements of $20,455,000 of bonds in 1992. At December 31, 1992, outstanding debt included $998,950,000 of Electric System Revenue Bonds, a $4,550,000 subordinated obligation, Minibonds of $10,000,000 and TECP of $50,000,000.

Gross Electric Plant amounted to $1,929,502,000 and Nuclear Fuel (at amortized cost) amounted to $120,834,000 at December 31, 1992. Accumulated earnings reinvested in the business increased $30,255,000 to a total of $665,950,000 during 1992 while total assets increased $114,249,000 to a total of $1,947,826,000.

INDEPENDENT AUDITORS' REPORT

Omaha Public Power District:

We have audited the accompanying balance sheets of the Omaha Public Power District as of December 31, 1992 and 1991 and the related statements of net earnings and accumulated earnings reinvested in the business and of cash flows for each of the three years in the period ended December 31, 1992. These financial statements are the responsibility of the District's management. 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, such financial statements present fairly, in all material respects, the financial position of the Omaha Public Power District as of December 31, 1992 and 1991, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1992 in conformity with generally accepted accounting principles.

Deloitte & Touche

DELOITTE & TOUCHE
Omaha, Nebraska
February 18, 1993

OMAHA PUBLIC POWER DISTRICT
BALANCE SHEETS, DECEMBER 31, 1992 AND 1991

ASSETS	NOTES	1992	1991
		(thousands)	
UTILITY PLANT - At cost:	2,10		
Electric plant (includes construction work in progress of $92,376,000 and $95,583,000, respectively)		$1,929,502	$1,849,479
Less accumulated depreciation		656,420	610,514
Electric plant - net		1,273,082	1,238,965
Nuclear fuel - at amortized cost		120,834	137,200
Utility plant - net		1,393,916	1,376,165
SPECIAL PURPOSE FUNDS (primarily at amortized cost):	3,4		
Construction fund		119,546	71,271
Electric system revenue bond fund (net of current portion)		58,459	51,993
Debt service fund		-	6,160
Segregated fund		19,249	10,634
Segregated fund - collateralized securities		11,722	12,400
Decommissioning funds		53,684	46,396
Deferred compensation fund		41,984	33,775
Total special purpose funds		304,644	232,629
CURRENT ASSETS:			
Cash and cash equivalents		16,161	18,743
Electric system revenue bond fund - current portion		40,065	35,923
Accounts receivable		27,274	27,253
Unbilled revenues		16,075	14,917
Fossil fuels - at average cost		9,410	10,431
Materials and supplies - at average cost		36,272	40,590
Other		4,179	3,967
Total current assets		149,436	151,824
DEFERRED CHARGES	5	99,830	72,959
TOTAL		$1,947,826	$1,833,577

See notes to financial statements.

LIABILITIES	NOTES	1992	1991
		(thousands)	
LONG-TERM DEBT:	2		
Electric system revenue bonds - net of current portion:			
Serial bonds, 3.5% to 7.4% due annually from 1993 to 2010		$ 230,535	$ 177,220
Term bonds, 5-3/8% to 7-5/8% due at various dates from 1995 to 2017		749,505	694,050
Total electric system revenue bonds		980,040	871,270
Electric revenue notes - commercial paper series	6	50,000	100,000
Electric revenue notes - minibonds		10,000	-
Subordinated obligation		4,477	4,550
Total		1,044,517	975,820
Less unamortized discounts		8,492	9,510
Long-term debt - net		1,036,025	966,310
COMMITMENTS AND CONTINGENT LIABILITIES	10,11		
LIABILITIES PAYABLE FROM SEGREGATED FUND	3	15,407	10,634
CURRENT LIABILITIES:			
Current portion of electric system revenue bonds	2	18,910	20,455
Current portion of subordinated obligation		72	66
Accounts payable		33,387	38,129
Accrued payments in lieu of taxes		12,988	13,431
Accrued interest		24,375	24,009
Accrued production costs		295	10,300
Other		18,271	25,924
Total current liabilities		108,298	132,314
OTHER LIABILITIES:			
Decommissioning costs		53,684	46,396
Deferred compensation	8	41,984	33,775
Other	9	26,478	8,453
Total other liabilities		122,146	88,624
ACCUMULATED EARNINGS REINVESTED IN THE BUSINESS		665,950	635,695
TOTAL		$1,947,826	$1,833,577

STATEMENTS OF NET EARNINGS AND ACCUMULATED EARNINGS REINVESTED IN THE BUSINESS FOR THE THREE YEARS ENDED DECEMBER 31, 1992

	1992	1991	1990
		(thousands)	
OPERATING REVENUES	$ 373,113	$ 381,959	$ 386,648
OPERATING EXPENSES:			
Operation:			
Fuel	65,006	75,017	64,309
Other production	56,546	54,872	80,821
Transmission	2,334	2,356	2,232
Distribution	14,028	14,600	12,963
Customer accounts	10,647	10,488	9,396
Customer service and information	4,676	4,189	3,737
Administrative and general	29,822	29,806	28,726
Maintenance	43,004	45,902	39,225
Total operation and maintenance	226,063	237,230	241,409
Depreciation	52,465	50,237	47,514
Decommissioning	3,906	3,853	4,175
Payments in lieu of taxes	13,924	14,359	14,370
Total operating expenses	296,358	305,679	307,468
OPERATING INCOME	76,755	76,280	79,180
OTHER INCOME CREDITS (CHARGES):			
Interest income	16,348	16,631	19,790
Allowance for funds used during construction	3,383	3,993	3,687
Allowance for funds used for nuclear fuel	1,762	3,071	3,313
Other - net	(3,535)	(3,319)	(1,888)
Total other income credits - net	17,958	20,376	24,902
EARNINGS BEFORE INTEREST EXPENSE	94,713	96,656	104,082
INTEREST EXPENSE	64,458	61,447	63,745
NET EARNINGS	30,255	35,209	40,337
ACCUMULATED EARNINGS REINVESTED IN THE BUSINESS, BEGINNING OF THE YEAR	635,695	600,486	560,149
ACCUMULATED EARNINGS REINVESTED IN THE BUSINESS, END OF THE YEAR	$ 665,950	$ 635,695	$ 600,486

See notes to financial statements.

STATEMENTS OF CASH FLOWS
FOR THE THREE YEARS ENDED DECEMBER 31, 1992

	1992	1991	1990
		(thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Operating income	$ 76,755	$ 76,280	$ 79,180
Adjustments to reconcile operating income to net cash provided by operating activities:			
Depreciation	52,465	50,237	47,514
Amortization of nuclear fuel	19,597	23,881	17,798
Increase (decrease) in other liabilities	18,025	(1,865)	(4,057)
Other	(28,335)	(7,692)	(10,118)
Changes in current assets and liabilities:			
Revenue fund - U.S. Government securities	–	22,182	(19,188)
Accounts receivable	(21)	(3,385)	13,672
Unbilled revenues	(1,158)	1,654	(1,015)
Materials and supplies	4,318	(4,722)	(3,436)
Fossil fuels	1,021	(2,472)	610
Accounts payable	(4,742)	(581)	(9,352)
Accrued taxes	(443)	(17)	539
Other	(17,603)	16,973	9,129
Net cash provided from operating activities	119,879	170,473	121,276
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	374,158	–	–
Principal reduction of long-term debt	(310,141)	(19,601)	(17,626)
Interest paid on long-term debt	(61,725)	(59,823)	(62,548)
Acquisition and construction of capital assets	(83,199)	(91,552)	(78,310)
Acquisition of nuclear fuel	(1,469)	(14,266)	(1,876)
Net cash used for capital and related financing activities	(82,376)	(185,242)	(160,360)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Purchase of special purpose funds - investment securities	(872,160)	(590,413)	(283,719)
Sale and maturities of special purpose funds - investment securities	820,136	599,910	288,023
Net change in electric system revenue bond fund - current	(4,142)	(1,449)	(365)
Interest on investments	16,081	17,548	19,675
Net cash provided from (used for) investing activities	(40,085)	25,596	23,614
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(2,582)	10,827	(15,470)
CASH AND CASH EQUIVALENTS, BEGINNING OF THE YEAR	18,743	7,916	23,386
CASH AND CASH EQUIVALENTS, END OF THE YEAR	$ 16,161	$ 18,743	$ 7,916

See notes to financial statements.

NOTES TO FINANCIAL STATEMENTS FOR THE THREE YEARS ENDED DECEMBER 31, 1992

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Business - The Omaha Public Power District, a political subdivision of the State of Nebraska, is a public utility engaged solely in the generation, transmission, and distribution of electric power and energy and other related activities. The Board of Directors is authorized to establish rates. The District is not liable for Federal and State income or ad valorem taxes on property; however, payments in lieu of taxes are made to various local governments.

Basis of Accounting - The accounting records of the District are maintained generally in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission.

Accounting for Revenues - Meters are read and bills are rendered on a cycle basis. Revenues earned after meters are read are estimated and accrued as unbilled revenues at the end of each accounting period.

Utility Plant - The costs of property additions, replacements of units of property, and betterments are charged to electric plant. Maintenance and replacements of minor items are charged to operating expenses. Costs of depreciable units of electric plant retired are eliminated from electric plant accounts by charges, less salvage plus removal expenses, to the accumulated depreciation account.

An allowance for funds used, approximating the District's current cost of financing electric plant construction and the purchase of nuclear fuel, is capitalized as a component of the cost of the utility plant. This allowance was computed at 4.4%, 5.7% and 5.7% for both construction work in progress and nuclear fuel for the years ended in 1992, 1991 and 1990, respectively.

Depreciation and Amortization - Depreciation is computed on the straight-line basis at rates based on the estimated useful lives of the various classes of property. Depreciation expense has averaged approximately 3.6%, 3.6% and 3.7% of depreciable property for the years ended December 31, 1992, 1991 and 1990, respectively.

Amortization of nuclear fuel is based upon the cost thereof, which is pro-rated by fuel assembly in accordance with the thermal energy that each assembly produces.

Accrued Production Costs - Accrued production costs account for advance collections subject to refund under the Fuel and Production Cost Adjustment clause of the District's rate schedules.

Deferred Charges - Certain costs and charges are deferred and amortized over the period that ratepayers are expected to benefit. The most significant items are:

Deferred Financing Costs - Debt discount and expense and amortizable charges relating to refunded debt are amortized ratably over the lives of the related issues to which they pertain.

Safety Enhancement Program (SEP) - Fort Calhoun Station - Certain costs arising from the District's SEP at the Fort Calhoun Station have been deferred and are being amortized over ten years through 1999.

Federal Enrichment Facility Decommissioning and Decontamination Costs - Costs arising from the Energy Policy Act of 1992's funding mandate for the decommissioning and decontamination of Federal enrichment facilities have been deferred and are being amortized over fifteen years through 2007.

Nuclear Fuel Disposal Costs - Permanent disposal of spent nuclear fuel is the responsibility of the Federal Government under an agreement entered into with the United States Department of Energy (DOE). Under the agreement, the District is subject to a fee of one mill per net kilowatt-hour generated and sold on all nuclear energy generation, which is paid quarterly to the DOE. The spent nuclear fuel disposal costs are included in the District's nuclear fuel amortization and are collected from customers as part of fuel costs.

Nuclear Decommissioning - The District's Board of Directors has approved the collection of nuclear decommissioning costs based upon the Nuclear Regulatory Commission's (NRC's) external minimum funding requirements. The NRC's requirements are based on a generic estimate of the cost to decommission the radioactive portions of a nuclear unit based on the size and type of reactor. The estimate accepted by the NRC for the decommissioning of the Fort Calhoun Station - Unit No. 1, when its operating license is scheduled to expire in 2008, is $116,500,000 in 1992 dollars. The District is funding these costs in accordance with the NRC's requirements and will periodically review and adjust, if necessary, the funding level for changes in the estimated costs of decommissioning the plant.

During 1992, the District's Board of Directors adopted new decommissioning estimates totalling $312,000,000 in 1992 dollars, based upon an independent engineering study. The District is to commence funding of these new estimates effective January 1, 1993.

Cash and Cash Equivalents - For purposes of the Statements of Cash Flows, the District considers highly liquid investments of the Revenue Fund purchased with a maturity of three months or less to be cash equivalents.

2. LONG-TERM DEBT

The District utilizes proceeds of debt issues primarily in financing its construction program.

Electric System Revenue Bonds - Maturities of Electric System Revenue Bonds outstanding at December 31, 1992, due 1993 through 1997, are as follows (in thousands):

1993	$18,910
1994	$23,115
1995	$25,630
1996	$27,570
1997	$29,345

The District's bond indenture provides for certain restrictions, the most significant of which are:

Additional bonds may not be issued unless estimated net receipts (as defined) for each future year will equal or exceed 1.4 times the debt service on all bonds outstanding including the additional bonds being issued or to be issued in the case of a power plant (as defined) being financed in increments.

In any three-year period, at least 7-1/2% of general business income (as defined) must be spent for replacements, renewals, or additions to the electric system. Any deficiency is to be spent within two years thereafter for such purposes or if not so spent is to be used for bond retirements in advance of maturity.

In May 1992, the District issued $150,000,000 of 1992 Series A Electric System Revenue Bonds. A portion of the proceeds was used to reduce the balance of the District's Electric Revenue Notes - Commercial Paper Series by $100,000,000. Another portion of the proceeds amounting to $28,280,000 was used to redeem the principal and pay the call premium on the District's outstanding Original Bonds issued pursuant to Resolution No. 19.

In October 1992, the District issued $167,300,000 of 1992 Series B Electric System Revenue Bonds. Approximately $102,708,000 of the proceeds were placed in an irrevocable escrow to be used solely for satisfying scheduled payments of principal and interest on the outstanding 1989 Series A Electric System Revenue Bonds. The advance refunding reduced total debt service payments relating to the 1989 Series A Bonds by $367,000 over the next twenty-five years and created an economic gain (difference between the present value of the debt service of the refunded and refunding bonds) of $2,243,000.

In November 1992, the District placed securities with a carrying amount of $63,424,000 in an irrevocable escrow to be used solely for satisfying scheduled payments of principal and interest on the outstanding 1986 Series A Electric System Revenue Bonds.

At December 31, 1992 and 1991, the following Electric System Revenue Bonds are considered to be defeased:

	1992	1991
	(thousands)	
1985 Series A (7.50% - 9.35%)	$ 56,560	$57,245
1986 Series A (6.25% - 7-5/8%)	63,820	–
1989 Series A (6.50% - 6.80%)	97,800	–
Total	$218,180	$57,245

Such bonds are funded by Government securities deposited by the District in irrevocable escrow accounts. The bonds and the related Government securities escrow accounts have been removed from the District's balance sheet.

Electric Revenue Notes - Minibonds - The Minibonds consist of 6% current interest-bearing Minibonds and 6% capital appreciation Minibonds. The Minibonds are due October 1, 2007 and will be payable on a parity with the District's Electric Revenue Notes - Commercial Paper Series, both of which are subordinated to the outstanding bonds.

Subordinated Obligation - The subordinated obligation is payable in annual installments of $481,815, including interest, through 2014.

Fair Value Disclosure - The estimated fair value amount was determined using rates that are currently available for issuance of debt with similar credit ratings and maturities. As market interest rates decline in relation to the issuer's outstanding debt, the fair value of outstanding debt financial instruments with fixed interest rates and maturities will tend to rise. Conversely, as market interest rates increase, the fair value of outstanding debt financial instruments will tend to decline. Fair value will normally approximate carrying value as the debt financial instrument nears its maturity date. The use of different market assumptions may have an effect on the estimated fair value amount. Accordingly, the estimate presented herein is not necessarily indicative of the amount that bondholders could realize in a current market exchange.

At December 31, 1992, the aggregate carrying amount of the District's long-term debt, including current portion, was $1.063 billion and its approximate fair value was $1.080 billion.

NOTES TO FINANCIAL STATEMENTS FOR THE THREE YEARS ENDED DECEMBER 31, 1992 (CONTINUED)

3. SPECIAL PURPOSE FUNDS

Special purpose funds of the District are as follows:

The Construction Fund is to be used for capital improvements, additions and betterments to and extensions of the District's electric system, or for payment of principal and interest on Electric System Revenue Bonds.

The Electric System Revenue Bond Fund and Debt Service Fund are held by Trustees for the retirement of term and serial bonds and the payment of the related interest.

The Segregated Fund represents assets held for payment of customer deposits, refundable advances and certain other liabilities or refunds.

The Segregated Fund includes funds set aside as part of the District's self-insured health insurance plans. The balances of the funds at December 31 were as follows:

	1992	1991
	(thousands)	
Segregated Funds - customers	$15,407	$10,634
Segregated Funds - self-insurance	3,842	-
Total Segregated Funds	$19,249	$10,634

The Segregated Fund - Collateralized Securities represents investments in short-term securities (generally, repurchase agreements collateralized by Government securities) as permitted by State statute.

Decommissioning Funds are utilized to account for the investments held to fund the estimated cost of decommissioning Fort Calhoun Station - Unit No. 1 when its operating license is scheduled to expire in 2008. The Decommissioning Funds include an external trust fund to comply with the NRC's minimum funding requirements (see Note 1). The balances of the funds at December 31 were as follows:

	1992	1991
	(thousands)	
Decommissioning Trust - 1990 Plan	$48,053	$40,452
Segregated Fund - decommissioning	5,631	5,944
Total Decommissioning Funds	$53,684	$46,396

The Deferred Compensation Fund is valued at market value and is used to account for employee and District contributions and related earnings pursuant to the District's Supplemental Retirement Savings Plan (see Note 8).

4. DEPOSITS AND INVESTMENTS

Bank Deposits - The District's bank deposits at December 31, 1992 and 1991 were entirely insured or collateralized with securities held by the District or by its agent in the District's name.

Investments - The District's cash equivalents and investments included in the Construction Fund, Electric System Revenue Bond Fund, Debt Service Fund, Segregated Funds, and the Decommissioning Funds are held by the District's agents in the District's name in accordance with the District's bond covenants and State statutes. The composition of investments at December 31, 1992 and 1991 was as follows:

	1992		1991	
	Carrying Amount	Market Value	Carrying Amount	Market Value
	(thousands)			
U.S. Government and Agency Securities	$305,111	$313,342	$239,293	$242,109
Repurchase agreements (collateralized by Govt. Securities)	13,775	13,775	14,228	14,228
Total	$318,886	$327,117	$253,521	$256,337

5. DEFERRED CHARGES

The composition of deferred charges at December 31, 1992 and 1991 was as follows:

	1992	1991
	(thousands)	
Deferred financing costs	$36,806	$30,198
Safety Enhancement Program - Fort Calhoun Station	19,230	20,633
Federal enrichment facility decomissioning and decontamination costs	16,650	--
Other	27,144	22,128
Total	$99,830	$72,959

6. ELECTRIC REVENUE NOTES COMMERCIAL PAPER SERIES

The District has authorized the issuance of tax-exempt commercial paper of up to $50,000,000 at December 31, 1992 and up to $150,000,000 at December 31, 1991 which is supported by a credit agreement which expires in June 1993. At December 31, 1992 and 1991, the District had $50,000,000 and $100,000,000 of commercial paper issued and outstanding, respectively. The average borrowing rates at December 31, 1992 and 1991 were 2.7% and 4.1%, respectively.

7. PENSION PLAN

Substantially all employees of the District are covered by a defined benefit plan (the Plan) which provides retirement and death benefits. Employees are eligible for coverage at the time of employment with a vesting period of five years. Generally, the Plan provides for normal retirement at age 65. In 1991, the Plan was amended to provide unreduced early retirement benefits at age 62 with reduced benefits for retirements prior to age 62. Total payroll for all employees and covered payroll for the year ended December 31, 1992 were $110,145,000 and $96,635,000, respectively. Employees contribute 4.0% of their base pay to the Plan. The District is obligated to contribute the

balance of the funds needed on an actuarially determined basis. The Plan's funded status and amounts recognized in the District's balance sheets at December 31, 1992 and 1991 were as follows:

	1992	1991
	(thousands)	
Plan assets at fair value	$315,472	$301,127
Projected benefit obligation:		
Actuarial present value of accumulated:		
Vested benefits	182,012	161,028
Nonvested benefits	10,084	7,716
Effect of projected salary increases	66,585	53,637
Excess of plan assets over projected benefit obligation	56,791	78,746
Unrecognized transitional asset	(8,452)	(9,391)
Unrecognized net gain	(69,635)	(91,253)
Unrecognized prior service cost	20,724	19,378
Unfunded accrued pension cost	$ (572)	$ (2,520)

The projected benefit obligation was determined using an assumed discount rate of 8.0% for 1992 and 1991. Plan assets are primarily listed stocks, corporate bonds, and U. S. Government securities. There are no District securities included in the Plan assets. The expected long-term rate of return on assets was 8.0% for 1992 and 1991. An average annual rate of compensation increase of 6.0% was also assumed for 1992 and 1991. The unrecognized transitional asset is being amortized on a straight-line basis over fifteen years by annual credits to net periodic pension cost.

Net periodic pension cost for 1992, 1991 and 1990 included the following components:

	1992	1991	1990
		(thousands)	
Service cost	$ 4,890	$ 3,357	$ 3,160
Interest cost	19,123	17,495	15,382
Actual return on assets	(22,805)	(62,154)	(9,987)
Net amortization and deferral	(3,156)	41,486	(9,688)
Net pension expense (income)	$(1,948)	$ 184	$(1,133)

The pension benefit obligation, which is the actuarial present value of credited projected benefits, is a standardized disclosure measure of the present value of pension benefits, adjusted to include the effect of projected salary increases estimated to be payable in the future as a result of employee service to date. Based upon the most recent actuarial valuation on January 1, 1992, the pension benefit obligations at December 31, 1992 and 1991 were as follows:

	1992	1991
	(thousands)	
Retirees and beneficiaries receiving benefits	$ 97,122	$ 99,601
Terminated vested employees	1,844	1,501
Accumulated current employee contributions	59,106	53,595
District-financed vested benefits	92,702	73,492
District-financed nonvested benefits	7,907	10,932
Total pension benefit obligations	$258,681	$239,121

Contribution requirements are actuarially determined, using the Attained Age (level percent of pay) Method. The frozen initial liability is amortized over a 30-year period. Assumption changes and Plan amendments are amortized over a 10-year period. The actuarial assumptions used to compute the actuarially determined contribution requirements were the same as those used to compute the projected benefit obligation, except a 9.0% discount rate was used. Plan contributions by District employees for the years ended December 31, 1992 and 1991 were $3,865,000 and $3,630,000, respectively. The District has not contributed to the Plan during the last three years. All assumptions and methods used for the January 1, 1992 valuation are the same as the January 1, 1991 valuation.

Three-year historical trend information as of December 31 is as follows:

	Net Assets Available for Benefits (Col. 1)	Pension Benefit Obligation (Col. 2)	Col. 1 as % of Col. 2 (Col. 3)	Assets in Excess of Pens. Ben. Obligation (Col. 4)	Annual Covered Payroll (Col. 5)	Col. 4 as % of Col. 5 (Col. 6)
	(thousands)			(thousands)		
1990	$247,341	$210,116	117.7	$37,225	$84,755	43.9
1991	301,127	239,121	125.9	62,006	90,761	68.3
1992	315,472	258,681	122.0	56,791	96,635	58.8

Ten-year historical trend information, as available, is disclosed in the District's comprehensive annual financial report.

8. SUPPLEMENTAL RETIREMENT SAVINGS PLAN

The District has established a Deferred Compensation Fund for all eligible employees that allows contributions by employees that are partially matched by the District. By agreement, contributions and related earnings under the Plan remain the property of the District until an employee leaves the District. The District's matching share of contributions in 1992, 1991 and 1990 was $2,024,000, $1,522,000 and $1,144,000, respectively.

NOTES TO FINANCIAL STATEMENTS FOR THE THREE YEARS ENDED DECEMBER 31, 1992 (CONTINUED)

9. SELF-FUNDED HEALTH INSURANCE PROGRAM

The District's Administrative Service Only Health Insurance Program commenced January 1, 1992. The self-insured health insurance plans are used to account for the health insurance claims of both active and retired employees. Reserves sufficient to satisfy both statutory and District-directed requirements have been established to provide risk protection. Additionally, private insurance covering claims in excess of 120% of expected levels, as actuarially determined, has been purchased. Actual net claim payments during 1992 were $9,234,600 which did not exceed 120% of the expected claims level.

10. COMMITMENTS

The District's Construction Budget provides for expenditures of approximately $118,405,000 during 1993 and $73,722,000 during later years, of which approximately $21,300,000 was under contract at December 31, 1992.

The District has coal supply contracts which extend through 1998 with minimum future payments of $37,825,000. The District also has a coal transportation contract with minimum future payments of $76,700,000. These contracts are subject to price escalation adjustments.

Contracts with estimated future payments of $11,700,000 are in effect for nuclear fuel. In addition, the estimated cost of furnishing uranium enrichment services through 2008 is $112,000,000, of which $42,000,000 is under contract at December 31, 1992.

11. CONTINGENT LIABILITIES

Effective August 22, 1988, the Price-Anderson Act was amended and extended to the year 2002. Under the provisions of the Act, the District and all other licensed nuclear power plant operators could each be assessed for claims in the event of a nuclear incident in amounts not to exceed a total of $66,200,000 per reactor per incident with a maximum of $10,000,000 per incident in any one calendar year. These amounts are subject to adjustment every five years in accordance with the Consumer Price Index.

The District is engaged in routine litigation incidental to the conduct of its business and, in the opinion of its General Counsel, the aggregate amounts recoverable from or to the District, taking into account estimated amounts provided in the financial statements and insurance coverage, are not material.

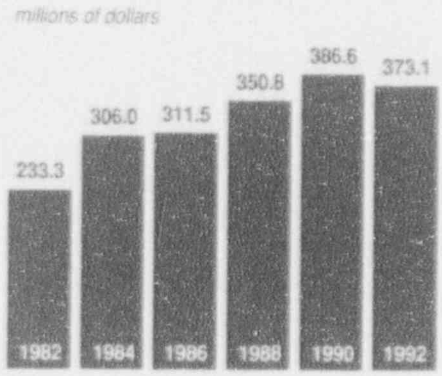
NET RECEIPTS AND DEBT SERVICE COVERAGE FOR THE FIVE YEARS ENDED DECEMBER 31, 1992 (UNAUDITED)

	1992	1991	1990	1989	1988
			(thousands)		
Operating revenues	**$373,113**	$381,959	$386,648	$375,643	$350,837
Operation and maintenance expenses	**226,063**	237,230	241,409	246,204	214,703
Payments in lieu of taxes	**13,924**	14,359	14,370	13,817	12,358
Net operating revenues	**133,126**	130,370	130,869	115,622	123,776
Investment income (1)	**4,356**	4,874	5,286	5,166	4,819
Net receipts	**$137,482**	$135,244	$136,155	$120,788	$128,595
Total debt service (2)	**$ 74,268**	$ 73,676	$ 73,638	$ 69,320	$ 65,867
Debt service coverage	**1.85**	1.83	1.84	1.74	1.95

(1) Income derived from the investment of moneys in the Debt Service Fund and the Reserve Account of the Electric System Revenue Bond Fund under the District's bond indentures (Resolution No. 19 and Resolution No. 1788).

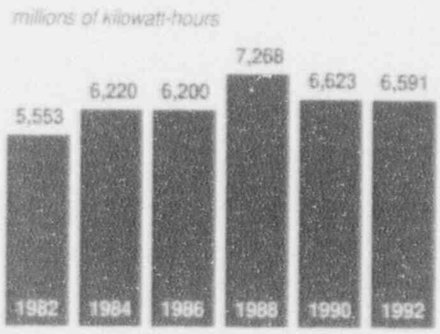
(2) Total Debt Service for both Resolution No. 19 and Resolution No. 1788 Bonds is accrued on a calendar-year basis similar to the computation of Net Receipts. Interest funded from bond proceeds is not included in Total Debt Service.

1992-1991 COMPARISONS



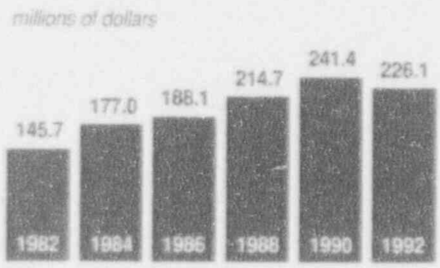
OPERATING REVENUES
(thousands)

Classification	Year 1992	Percent of Total	Year 1991	Percent of Increase (Decrease)
Residential	$141,992	38.1	$154,215	(7.9)
General Service - Small	135,262	36.2	135,059	0.2
General Service - Large	75,992	20.4	76,222	(0.3)
Government and Municipal	10,186	2.7	9,651	5.5
Other Electric Utilities	3,046	0.8	3,095	(1.6)
Accrued Unbilled Revenues	1,158	0.3	(1,654)	170.0
Total Electric Revenues	$367,636	98.5	$376,588	(2.4)
Miscellaneous Revenues	5,477	1.5	5,371	2.0
Total Operating Revenues	$373,113	100.0	$381,959	(2.3)



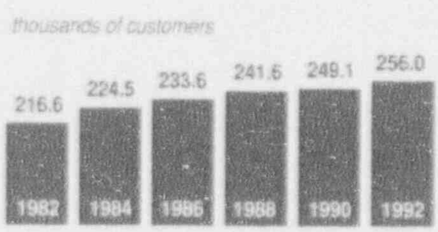
KILOWATT- HOUR SALES
(thousands)

Classification	Year 1992	Percent of Total	Year 1991	Percent of Increase (Decrease)
Residential	2,139,300	32.5	2,431,265	(12.0)
General Service - Small	2,355,409	35.7	2,372,148	(0.7)
General Service - Large	1,858,243	28.2	1,849,141	0.5
Government and Municipal	80,731	1.2	79,087	2.1
Other Electric Utilities	138,862	2.1	153,669	(9.6)
Accrued Unbilled Kilowatt-Hours	18,832	0.3	(26,123)	172.1
Total Energy Sales	6,591,377	100.0	6,859,187	(3.9)



OPERATION AND MAINTENANCE EXPENSES
(thousands)

Classification	Year 1992	Percent of Total	Year 1991	Percent of Increase (Decrease)
Generating Expense	$164,551	72.8	$177,759	(7.4)
Purchased and Interchanged Power	(14,321)	(6.3)	(15,932)	10.1
Transmission and Distribution	29,584	13.1	29,844	(0.9)
Customer Accounts	10,647	4.7	10,488	1.5
Customer Service and Information	4,676	2.0	4,189	11.6
Administrative and General	30,926	13.7	30,882	0.1
Total Operation and Maintenance Expenses	$226,063	100.0	$237,230	(4.7)



AVERAGE NUMBER OF CUSTOMERS*

Classification	Year 1992	Percent of Total	Year 1991	Percent of Increase (Decrease)
Residential	224,107	87.6	221,214	1.3
General Service - Small	31,259	12.2	30,626	2.1
General Service - Large	92	–	91	1.1
Other	502	0.2	496	1.2
Average Customers	255,960	100.0	252,427	1.4

*Average Total Twelve Months Ended December

ELECTRIC SYSTEM REVENUE BONDS OUTSTANDNG

(In Thousands) as of December 31, 1992

	1972 ISSUE		1973 ISSUE		1977 ISSUE SERIES A		1977 ISSUE SERIES B		1977 ISSUE SERIES C		1992 ISSUE SERIES A		1992 ISSUE SERIES B			
Maturity Date Feb. 1	Int. Rate	Amt.	Int. Rate	Amt.	Int. Rate	Amt.	Int. Rate	Amt.	Int. Rate	Amt.	Int. Rate	Amt	Int. Rate	Amt.	Total Principal Maturities (Feb. 1)	Annualized Debt Service
1993	5.20	5,390	5.40	950	5 ½	4,150			5.20	3,620	3.15	4,800			18,910	80,370
1994	5.20	5,685	5.40	1,000	5.60	4,500			5 ¼	3,720	4.30	5,000	3 ½	3,210	23,115	81,920
1995	5 ¾*	6,000	5 ¾*	1,050	5.70	4,900			5.30	3,970	4.70	6,500	3.90	3,210	25,630	82,520
1996	5 ¾*	6,330	5 ¾*	1,110	5 ¾	5,350			5.40	4,170	5	7,000	4 ¼	3,610	27,570	82,980
1997	5 ¾*	6,680	5 ¾*	1,170	5.80	7,300			5.45	4,485	5.20	6,000	4.60	3,710	29,345	82,923
1998	5 ¾*	7,045	5 ¾*	1,235	5.85	7,900			5 ½	4,590	5.40	6,000	4.80	4,060	30,830	83,023
1999	5 ¾*	7,430	5 ¾*	1,300	5.90	10,900			5 ½	4,960	5.55	3,500	5	4,540	32,630	83,027
2000	5 ¾*	7,840	5 ¾*	1,370	6*	12,600			5 ¾*	5,335	5.70	3,000	5.20	4,290	34,435	83,020
2001	5 ¾*	8,275	5 ¾*	1,450	6*	13,450			5 ¾*	5,470	5.80	3,000	5.35	4,740	36,385	83,026
2002	5 ¾*	8,725	5 ¾*	1,525	6*	14,350			5 ¾*	5,710	5.90	3,000	5 ½	5,160	38,470	83,030
2003	5 ¾*	9,205	5 ¾*	1,610	6*	15,250			5 ¾*	5,955	6.00	4,500	5.60	4,160	40,680	83,028
2004	5 ¾*	9,715			6*	17,300			5 ¾*	6,820	6.10	4,500	5.70	4,690	43,025	83,019
2005	5 ¾*	10,250			6*	18,550			5 ¾*	6,970	6.20	5,500	5.80	4,240	45,510	82,962
2006	5 ¾*	10,810			6*	19,900			5 ¾*	7,140	6.25	5,500	5.90	4,750	48,100	82,998
2007					6*	30,100			5 ¾*	9,885	6.30	6,000	6	4,970	50,955	73,321
2008							6 ⅛*	12,900	5 ¾*	10,780	6.35	9,000	6.05	10,765	43,445	69,950
2009							6 ⅛*	13,670	5.90*	11,200	6.35	9,000	6.15*	9,490	43,360	68,300
2010							6 ⅛*	14,490	5.90*	11,730	6.40*	9,000	6.15*	9,240	44,460	66,146
2011							6 ⅛*	15,360	5.90*	12,345	6.40*	8,000	6.15*	9,270	44,975	65,690
2012							6 ⅛*	16,285	5.90*	13,005	6½*	8,000	6.15*	10,140	47,430	64,934
2013							6 ⅛*	17,260	5.90*	13,715	6½*	7,000	6.20*	11,565	49,540	63,649
2014							6 ⅛*	18,295	5.90*	14,435	6½*	7,000	6.20*	11,520	51,250	62,382
2015							6 ⅛*	19,395	5.90*	15,215	6½*	7,000	6.20*	11,520	53,130	62,227
2016							6 ⅛*	20,555	5.90*	16,775	6½*	7,000	6.20*	12,000	56,330	43,579
2017							6 ⅛*	21,790			6½*	5,200	6.20*	12,450	39,440	3,490
Total Outstanding		109,380		13,770		186,500		170,000		202,000		150,000		167,300	998,950	1,801,614
Bonds Redeemed to 12/31/92		60,620		11,230		13,500				27,200					112,550	
Original Issue		170,000		25,000		200,000		170,000		229,200		150,000		167,300	1,111,500	

*Term Bonds

The 1985 Series A Issue was advance refunded and will be called on February 1, 1995.

The 1986 Series A Issue was defeased to maturity with final maturity on February 1, 2015.

The 1989 Series A Issue was advance refunded and will be called on February 1, 2000.

ELECTRIC STATISTICS

	1992	1991	1990	1989	1988	1987	1986	1985	1984	1983
Total Utility Plant, including Nuclear Fuel *(at year end)* *(in thousands of dollars)*	**2,050,336**	1,986,679	1,897,546	1,824,757	1,735,654	1,646,734	1,561,960	1,495,254	1,425,461	1,365,553
Bonded Indebtedness (at year end) *(in thousands of dollars)*	**998,950**	891,725	911,265	928,835	845,595	861,605	876,945	880,055	833,350	846,505
Operating Revenues *(in thousands of dollars)*										
Residential	**141,992**	154,215	152,464	146,458	137,105	125,095	121,541	111,975	116,368	108,722
General Service - Small	**135,262**	135,059	135,774	134,821	117,711	108,543	105,445	97,321	98,300	82,880
General Service - Large	**75,992**	76,222	78,375	72,416	61,637	57,561	57,776	55,360	55,444	46,226
Government and Municipal	**10,186**	9,651	9,685	8,417	7,961	7,726	7,574	7,388	7,099	6,519
Other Electric Utilities	**3,046**	3,095	3,824	5,825	20,592	18,623	17,395	21,451	25,129	22,958
Accrued Unbilled Revenues	**1,158**	(1,654)	1,015	2,753	874	211	(2,482)	5,500	(600)	1,900
Miscellaneous	**5,477**	5,371	5,511	4,953	4,957	4354	4,249	4,041	4,259	3,642
Total	**373,113**	381,959	386,648	375,643	350,837	322,113	311,498	303,036	305,999	272,847
Operation & Maintenance Expenses Charged to Operations *(in thousands of dollars)*	**226,063**	237,230	241,409	246,204	214,703	193,173	188,099	172,438	177,001	156,950
Payments in Lieu of Taxes *(in thousands of dollars)*	**13,924**	14,359	14,370	13,817	12,358	11,347	10,968	10,107	10,292	9,034
Net Operating Revenues before Depreciation and Decommissioning *(in thousands of dollars)*	**133,126**	130,370	130,869	115,622	123,776	117,593	112,431	120,491	118,706	106,863
Net Earnings Reinvested in the Business *(in thousands of dollars)*	**30,255**	35,209	40,337	29,584	36,929	31,020	28,016	40,256	40,007	27,929
Kilowatt-Hour Sales *(in thousands)*										
Residential	**2,139,300**	2,431,265	2,292,975	2,246,496	2,311,242	2,153,681	2,109,493	1,966,119	2,041,395	2,115,696
General Service - Small	**2,355,409**	2,372,148	2,275,647	2,304,856	2,246,353	2,130,425	2,073,447	1,926,936	1,940,767	1,830,190
General Service - Large	**1,858,243**	1,849,141	1,831,635	1,713,362	1,655,600	1,562,108	1,535,819	1,497,052	1,471,372	1,384,986
Government and Municipal	**80,731**	79,087	78,514	77,215	76,133	75,622	75,356	75,279	74,696	74,781
Other Electric Utilities	**138,862**	153,669	137,166	44,935	961,298	719,807	405,512	529,759	691,792	590,987
Accrued Unbilled Kilowatt-Hours	**18,832**	(26,123)	6,695	29,914	17,010	(13,682)	(56,104)	114,720	-	-
Total	**6,591,377**	6,859,187	6,622,632	6,416,778	7,267,636	6,627,961	6,143,523	6,109,865	6,220,022	5,996,640
Number of Customers *(average per year)*										
Residential	**224,107**	221,214	210,373	215,194	212,324	209,900	205,538	201,662	197,750	193,638
General Service - Small	**31,259**	30,626	30,117	29,439	28,731	28,109	27,623	26,966	26,271	25,245
General Service - Large	**92**	91	90	75	75	76	76	75	73	73
Government and Municipal	**497**	491	475	457	433	417	405	391	400	392
Other Electric Utilities	**5**	5	5	4	5	6	7	6	7	7
Total	**255,960**	252,427	249,060	245,169	241,568	238,508	233,649	229,100	224,501	219,355
Residential Statistics *(average)*										
kWh/Customer	**9,546**	10,991	10,500	10,439	10,885	10,261	10,263	9,750	10,323	10,926
Dollar Revenue/Customer	**633.59**	697.13	698.18	680.59	645.73	595.97	591.33	555.26	588.46	561.47
Cents/kWh	**6.64**	6.34	6.65	6.52	5.93	5.81	5.76	5.70	5.70	5.14
Generating Capability *(at year end)* *(in kilowatts)*	**1,883,500**	1,883,300	1,867,200	1,867,900	1,823,000	1,846,900	1,892,300	1,896,200	1,994,500	1,997,500
System Peak Loads *(in kilowatts)*	**1,442,000**	1,605,900	1,652,300	1,597,000	1,600,400	1,532,700	1,435,600	1,331,200	1,383,900	1,411,500
Net System Requirements *(kilowatt-hours in thousands)*										
Generated	**7,653,496**	9,129,971	7,721,410	7,202,585	7,756,360	7,511,779	7,322,999	6,850,069	6,712,772	6,302,725
Purchased and Net Interchanged	**(844,178)**	(2,038,980)	(864,931)	(426,299)	(1,050,747)	(1,237,120)	(1,187,400)	(915,987)	(860,382)	(483,636)
Net	**6,809,318**	7,090,991	6,856,479	6,776,286	6,705,613	6,274,659	6,135,599	5,934,082	5,852,390	5,819,089

( ) Denotes Negative

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Richard F. Locke
Attorney at Law

PG&E

March 22, 1993

The Director
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Re: Docket No. 50-133
Docket No. 50-275
Docket No. 50-323

Dear Sir:

Enclosed are ten copies of Pacific Gas and Electric Company's Annual Report and Financial Information for the calendar year 1992.

Very truly yours,

Richard F. Locke

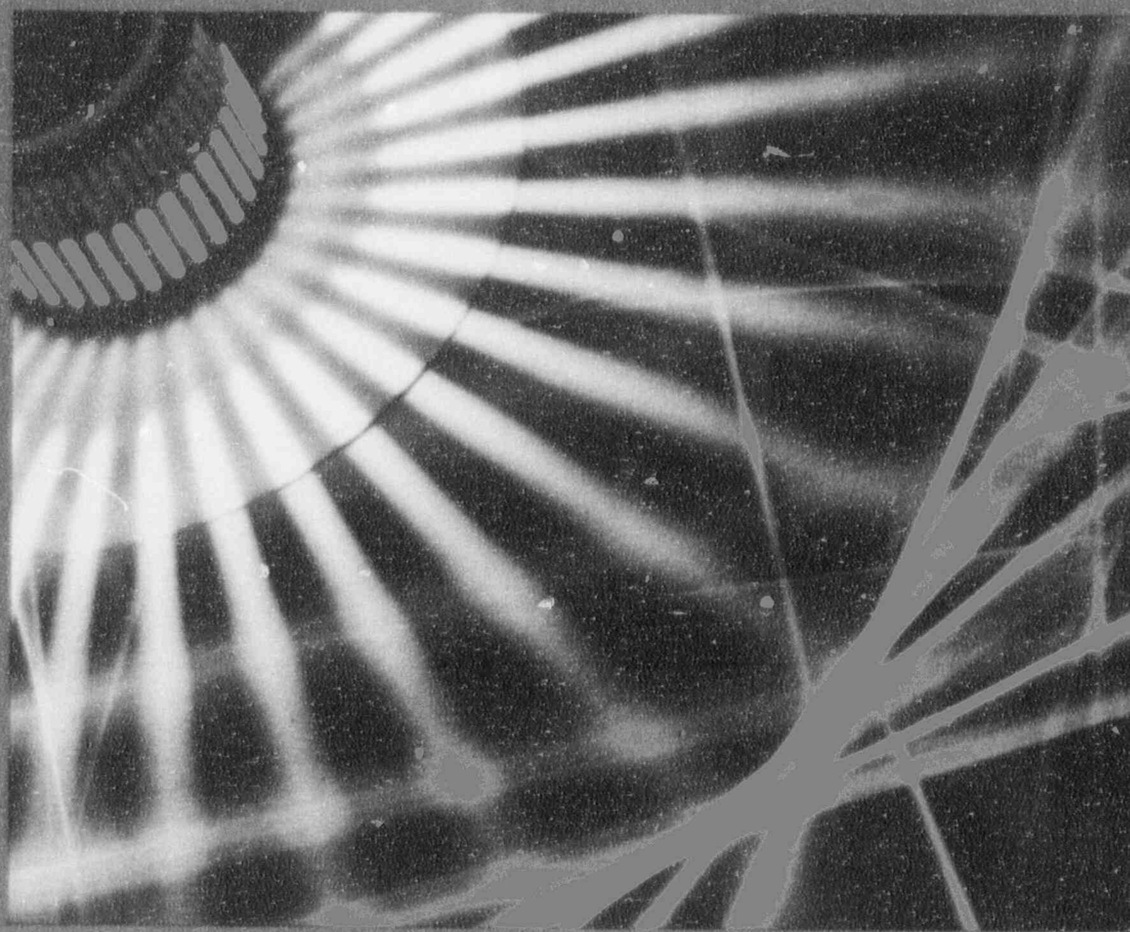
RICHARD F. LOCKE
RFL:af
Enclosures
[An-Rep.NRC]

cc:w/out encl.

Sheri Peterson
Jerome D. Saltzman, NRC

M004
1/10

PACIFIC GAS AND ELECTRIC COMPANY



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INFORMA

Pacific Gas and Electric Company

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SELECTED FINANCIAL DATA

(in thousands, except per share amounts)	1992	1991	1990	1989	1988
FOR THE YEAR					
Operating revenues	$10,296,088	$ 9,778,119	$ 9,470,092	$ 8,588,264	$ 7,645,748
Operating income	1,833,441	1,713,079	1,706,136	1,622,558	1,297,372
Net income	1,170,581	1,026,392	987,170	900,628	62,127
Earnings (loss) per common share	2.58	2.24	2.10	1.90	(.10)
Dividends declared per common share	1.76	1.64	1.52	1.40	1.66
AT YEAR END					
Book value per common share	19.41	18.40	17.86	17.38	16.79
Common stock price per share	33.13	32.63	25.00	22.00	17.50
Total assets	24,188,159	22,900,670	21,958,397	21,351,970	21,067,685
Long-term debt and preferred stock with mandatory redemption provision (excluding current portions)	8,525,948	8,341,310	7,902,409	7,951,320	7,948,958

Matters relating to certain data above are discussed in Management's Discussion and Analysis of Consolidated Results of Operations and Financial Condition and in Notes to Consolidated Financial Statements. In 1988, net income was reduced by $576 million ($1.43 per share) as a result of the Diablo Canyon Nuclear Power Plant rate case settlement and adjustments for various non-Diablo Canyon costs.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF CONSOLIDATED RESULTS OF OPERATIONS AND FINANCIAL CONDITION

Results of Operations

Pacific Gas and Electric Company (PG&E) and its wholly owned and majority-owned subsidiaries (the Company) have three types of operations: utility, Diablo Canyon Nuclear Power Plant (Diablo Canyon) and nonregulated through PG&E Enterprises (Enterprises). For 1992, 1991 and 1990, selected financial information for the three types of operations is shown below:

(in millions, except per share amounts)	Utility	Diablo Canyon (1)	Enterprises	Total
1992				
Operating revenues				
Electric	$ 5,966	$1,781	$ --	$ 7,747
Gas	2,340	—	209	2,549
Total operating revenues	8,306	1,781	209	10,296
Operating expenses	7,125	1,118	220	8,463
Operating income (loss)	$ 1,181	$ 663	$ (11)	$ 1,833
Net income (loss)	$ 738	$ 443	$ (10)	$ 1,171
Earnings (loss) per common share	1.61	.99	(.02)	2.58
Total assets at year end	17,759	5,494	935	24,188
1991				
Operating revenues				
Electric	$ 5,868	$1,501	$ —	$ 7,369
Gas	2,336	—	73	2,409
Total operating revenues	8,204	1,501	73	9,778
Operating expenses	6,953	1,004	108	8,065
Operating income (loss)	$ 1,251	$ 497	$ (35)	$ 1,713
Net income (loss)	$ 777	$ 274	$ (25)	$ 1,026
Earnings (loss) per common share	1.71	.59	(.06)	2.24
Total assets at year end	16,440	5,543	918	22,901
1990				
Operating revenues				
Electric	$ 5,527	$1,509	$ —	$ 7,036
Gas	2,372	—	62	2,434
Total operating revenues	7,899	1,509	62	9,470
Operating expenses	6,710	959	95	7,764
Operating income (loss)	$ 1,189	$ 550	$ (33)	$ 1,706
Net income (loss)	$ 688	$ 318	$ (19)	$ 987
Earnings (loss) per common share	1.48	.67	(.05)	2.10
Total assets at year end	15,869	5,660	429	21,958

(1) See Note 3 of Notes to Consolidated Financial Statements for discussion of allocations.

Earnings Per Common Share: Earnings per common share for 1992 were higher than for 1991 primarily due to one scheduled refueling outage at Diablo Canyon in 1992, compared to two scheduled refueling outages in 1991, and the annual increase in the price per kilowatthour (kWh) as provided in the Diablo Canyon rate case settlement. Earnings per common share for 1991 were higher than for 1990 primarily due to a $66 million after-tax charge to 1990 utility earnings related to the reserve for certain Helms Pumped Storage Plant (Helms) costs, including litigation settlement costs, discussed in Note 10 of Notes to Consolidated Financial Statements. In 1992 and 1991, the Company earned a 13.7% and a 12.5% return on average common stock equity, respectively, and a 10.2% and an 11.3% return on average utility rate base, respectively. The average utility rate base for 1992 and 1991 was $11 billion.

Common Stock Dividend: In January 1993, the Company raised the quarterly common stock dividend 6.8%, from an annualized rate of $1.76 per share to $1.88 per share, the fourth dividend increase in four years. The increase was based on a number of financial considerations, including estimates that future earnings will be sufficient to sustain the higher dividends while providing adequate financial flexibility.

Operating Revenues: Electric revenues increased $378 million and $333 million in 1992 and 1991, respectively, compared to the preceding year. The increase in 1992 electric revenues was primarily due to one scheduled refueling outage at Diablo Canyon in 1992, compared to two scheduled refueling outages in 1991, and the annual increase in the price per kWh as provided in the Diablo Canyon rate case settlement.

The 1991 increase in electric revenues was primarily due to increased utility rates necessary to recover higher fuel and purchased power costs.

Gas revenues increased $140 million and decreased $25 million in 1992 and 1991, respectively, compared to the preceding year. The 1992 increase was primarily due to increased revenues generated by Enterprises as the result of the December 1991 acquisition of TEX/CON Oil & Gas Company.

The 1991 decrease in gas revenues was primarily due to a decrease in the cost of purchased gas, partially offset by rate adjustments related to an increase in operating expenses resulting from inflation and a higher rate base.

Operating Expenses: In 1992 and 1991, the Company's operating expenses increased $398 million and $301 million, respectively, over the preceding year.

The 1992 increase was primarily due to increases in the cost of gas, the cost of electric energy, and depreciation and decommissioning expense. The cost of gas increased in 1992 by $103 million over the preceding year, primarily due to an increase in the cost of gas purchased on behalf of, and transported for, noncore customers. The cost of electric energy increased $98 million in 1992 compared to 1991, primarily due to increases in the cost of purchased power and natural gas. An $81 million increase in depreciation and decommissioning expense reflects the increase in plant in service.

The 1991 increase in operating expenses was primarily due to a $121 million increase in maintenance expense (which reflects two Diablo Canyon scheduled refueling outages), a $94 million increase in depreciation and decommissioning expense, an $84 million increase in the cost of electric energy and an $82 million increase in administrative and general expense, partially offset by a $208 million decrease in the cost of gas.

Other Income and (Income Deductions): Total other income and (income deductions) were $124 million, $95 million and $85 million for 1992, 1991 and 1990, respectively.

Allowance for equity funds used during construction was $39 million, $25 million and $25 million for 1992, 1991 and 1990, respectively. The increase in 1992 over 1991 was primarily due to the PGT-PG&E pipeline expansion project.

Other—net for 1992 includes a $19 million after-tax gain from the sale by Pacific Gas Transmission Company (PGT), a wholly owned gas pipeline subsidiary of the Company, of its 49.98% interest in Alberta Natural Gas Company Ltd (ANG) to TransCanada PipeLines Limited (TransCanada). Other—net for 1992 also reflects the establishment of new accounting guidelines for the recognition of revenues related to customer energy efficiency programs, which resulted in a $25 million decrease in the amount of income recognized in 1992 compared to 1991.

Included in 1991 other—net is the write-off by ANG of its investment in a magnesium metal production facility project in Alberta, Canada. This write-off resulted in a $26 million after-tax charge. Other—net for 1990 includes the $66 million after-tax charge resulting from the Helms litigation reserve.

Diablo Canyon: The Diablo Canyon rate case settlement bases revenues for the plant primarily on the amount of electricity generated, rather than on traditional cost-based ratemaking. Under this "performance-based" approach, the Company assumes a significant portion of the operating risk of the plant because the extent and timing of the recovery of actual operating costs, depreciation and a return on the investment in the plant primarily depend on the amount of power produced and the level of costs incurred. The Company's earnings are affected directly by plant performance and costs incurred.

Diablo Canyon revenues are based primarily on a pre-established price for each kWh of electricity generated by the plant. (Pricing for Diablo Canyon is discussed in Note 3 of Notes to Consolidated Financial Statements.) From the revenues received for Diablo Canyon, the Company must recover the costs of owning and operating the plant, including all future capital additions. If power generation drops below specified capacity levels, the Company may request floor payments which ensure that the Company will receive some revenue, even if the plant stops producing power. However, payments received must be refunded to customers under specified conditions. Decommissioning and certain specific costs will continue to be recovered through base rates and are not subject to plant performance.

In September 1992, a consumer advocacy group filed a petition with the California Public Utilities Commission (CPUC) seeking to modify the CPUC's 1988 decision that adopted the Diablo Canyon rate case settlement entered into by the California Attorney General, the CPUC's Division of Ratepayer Advocates (DRA) and the Company.

The petition contends that the Company has made unreasonably high profits because of the better-than-expected operating performance of Diablo Canyon. The petition does not propose any specific change to the Diablo Canyon rate provisions, but requests that the CPUC reopen the Diablo Canyon rate case settlement to consider mechanisms for sharing with ratepayers additional benefits of Diablo Canyon's performance. The Company has filed a response to the petition and believes the petition is without merit, is contrary to law and should be dismissed. The California Attorney General also filed a letter urging the CPUC to summarily reject the petition.

The plant capacity factors for 1992 and 1991 were 88% and 80%, respectively, reflecting the scheduled refueling outages for Unit 1 in 1992 and both Unit 1 and Unit 2 in 1991. There were no extended unscheduled outages in 1992 and 1991. Through December 31, 1992, the lifetime capacity factor for the plant was 78%. The Company will report significantly lower revenues for the plant during any extended outages, including refueling outages. Refueling outages, the lengths of which depend on the scope of the work, typically occur for each unit every eighteen months. A refueling outage for Unit 2 is scheduled to begin in March 1993 and is planned to last about eleven weeks. There is no refueling outage scheduled for Unit 1 in 1993. Each Diablo Canyon unit will contribute approximately $2.9 million in revenues per day at full power operation in 1993. Diablo Canyon revenues per kWh after 1994 will be based on a formula that relates to the prior year's change in the consumer price index.

Regulatory Matters: The Company's electric and gas energy prices are regulated by the CPUC through base rates and balancing accounts. Base rates compensate the Company for operating and maintenance costs, depreciation and taxes, and provide a return on capital. Base rates are set every three years in General Rate Case (GRC) proceedings. The base rates for 1992 were established in the 1990 GRC as adjusted by the Attrition Rate Adjustment (ARA). The ARA mechanism makes annual adjustments for certain changes in operating expenses and capital costs between rate cases.

Balancing accounts help stabilize the Company's earnings. The CPUC sets rates based on future estimates of revenues and costs; differences between revenues or costs authorized by the CPUC and actual revenues or costs are accumulated in the balancing accounts for subsequent rate adjustment. Energy cost balancing accounts reduce the effect on earnings of fluctuations in most electric energy and core gas costs. Sales balancing accounts reduce the effect on earnings of fluctuations in sales to electric and gas customers. Some of these balancing accounts are proposed by the CPUC to be changed as discussed below.

The regulatory framework in place has helped to neutralize the effects of inflation on the Company's utility operations. Both the ARA mechanism and the energy cost balancing accounts limit the effect of inflation on the Company's earnings by closely matching rates with costs.

The regulatory framework for the natural gas service (1) segments the Company's gas customers into core and noncore (industrial and commercial customers that meet certain size limitations) classes, (2) unbundles the Company's gas transportation and procurement services (i.e., the noncore customers are charged separate unbundled rates for gas transportation services and for gas procurement services), (3) allows the noncore customers to negotiate gas transportation service agreements and (4) places the Company at increased risk for collecting noncore transportation revenues.

Gas cost allocation proceedings allocate forecasted costs between core and noncore customers and set associated rates. This ratemaking mechanism covers a two-year forecast period and includes a balancing account, which until May 1992 allowed the Company to collect 90% of the difference between authorized and actual noncore transportation revenues. As a result, the Company is at increased risk for collecting noncore gas transportation revenues to the extent authorized revenues differ from actual. In May 1992, the 90% balancing account was discontinued and a 75% balancing account was established.

In December 1992, the CPUC proposed rules which would (1) extend the gas ratemaking cycle from two to three years and (2) replace the current 75% balancing account treatment with a mechanism that would provide no balancing account protection within a preset range of deviations between the noncore's authorized and actual revenues; within a wider range of deviations, progressively greater balancing account protection would be provided. The CPUC has requested comments on the proposed rules by mid-February 1993.

In November 1992, the CPUC issued an order that adopts, on an interim basis, a procedure for expedited approval of discounted long-term gas transportation contracts with noncore customers. Under this interim rule, the Company would be precluded from recovering in rates 25% of the revenue shortfalls resulting from discounts approved through the expedited procedure. In December 1992, the Company filed an application for rehearing requesting modification of certain aspects of this process, including objection to the 25% absorption of the discount by the Company.

Rate Proceedings: In December 1992, the CPUC issued its decision in the Company's 1993 GRC, granting the Company an annual increase in electric and gas revenue requirements of $255 million and $68 million, respectively, effective January 1, 1993. The electric and gas rate increases are mostly due to a higher rate base on which the Company is allowed to earn a return, general increases in operating expenses and increased costs for funding of

postretirement benefits other than pensions. The total $323 million revenue increase effective January 1, 1993 also incorporates the rate impact of the decisions in the Company's electric energy cost and sales balancing accounts proceedings and the Company's cost of capital proceeding. The Company's authorized utility capital structure for 1993 is 46.75% common equity (11.90% authorized return), 5.75% preferred stock (8.35% authorized return) and 47.50% long-term debt (8.61% authorized return). The 11.90% authorized common equity return for 1993 was decreased from 12.65% for 1992. The authorized utility capital structure and related returns result in a total authorized return of 10.13% on average utility rate base of $12 billion for 1993.

The following table shows the composition of actual total capitalization for the consolidated Company:

	December 31, 1992	December 31, 1991
Common equity	46%	45%
Preferred stock	5	6
Long-term debt	49	49
Total capitalization (1)	100%	100%

(1) Includes current portions of long-term debt and preferred stock with mandatory redemption provision.

In October 1992, the CPUC issued a decision in the Company's Biennial Cost Allocation Proceeding (BCAP). The decision resulted in a gas rate decrease totalling $437 million from current rates over a two-year period, consisting of decreases of $434 million in core gas revenues and $3 million in noncore gas revenues. The rate decrease primarily reflects lower forecasted gas costs and the return to customers of overcollections of gas costs from the prior period, which more than offset increases in other costs. The rate decrease was effective November 1, 1992. Therefore, the annual net decrease in the Company's gas revenue requirement resulting from the combined 1993 GRC and BCAP decisions is $150 million.

Natural Gas Matters: As discussed in Note 2 of Notes to Consolidated Financial Statements, Alberta and Southern Gas Co. Ltd. (A&S), a wholly owned subsidiary of the Company, currently has commitments to purchase minimum quantities of natural gas from Canadian producers. A number of these producers filed lawsuits against the Company claiming damages of at least $466 million (Canadian) for the alleged failure of A&S to meet its minimum contractual gas purchase obligations for the 1989-1992 contract years and for the anticipated failure of A&S to meet those obligations through 2005. Revised regulations initiated by the CPUC will require the Company to reduce its Canadian gas purchases and negotiate restructured gas supply arrangements. In addition, the Federal Energy Regulatory Commission (FERC) initiated regulations which require interstate pipelines to restructure their gas sales services.

As a result, in December 1992, A&S, PGT and PG&E proposed a restructuring plan to approximately 190 A&S gas producers to reduce present obligations, settle litigation and enter into contracts for future gas supply. Pursuant to the proposed restructuring plan, the Company offered to pay A&S gas producers a total of approximately $150 million to settle any claims they may have against A&S, PGT and PG&E that result from the restructuring of existing arrangements as well as any claims for losses arising from alleged historical shortfalls in gas taken by A&S. The restructuring plan is conditioned upon a number of U.S. and Canadian regulatory approvals, including a provision that would require the Company's shareholders to absorb a maximum of 30% of the transition payments. The financial impact will depend on the amount of the transition payments and the recovery mechanisms adopted by FERC and the CPUC, and other factors. The Company believes it is reasonably possible that the ultimate outcome of the litigation and gas contract restructuring will have a significant adverse impact on the Company's financial position or results of operations. However, at this stage in the restructuring process and in view of the uncertainties inherent in litigation and in rate recovery of any transition payments, the Company is unable to estimate the ultimate amount of such financial impact.

The CPUC periodically reviews the reasonableness of the Company's gas and electric operations. For 1988 through 1990, certain parties contend that the Company overpaid Canadian gas costs by up to $670 million. It is possible that similar issues will be raised regarding the Company's Canadian gas procurement activities during 1991, 1992 and until such time that the Canadian gas supply arrangements are restructured. The Company currently is unable to estimate the ultimate outcome of the reasonableness proceedings or predict whether such outcome will have a significant adverse impact on its financial position or results of operations.

Helms: As discussed in Note 10 of Notes to Consolidated Financial Statements, the Company provided a reserve of approximately $64 million against its investment in Helms as a result of an adverse decision in 1990 in the water conduit rupture litigation. As of December 31, 1992, the remaining net unrecovered costs and revenues related to Helms totalled $108 million. The Company has filed an application for rate recovery of the remaining unrecovered costs and revenues; however, the Company is uncertain whether, and to what extent, any of the remaining costs and revenues will be recovered through the ratemaking process.

Competition: The Company is currently experiencing increasing competition in both the gas and electric energy markets. In recent years, changes in governmental regulations, new technology, interest in self-generation and cogeneration, and competition from nonregulated energy

suppliers have provided many major utility customers with alternative sources to satisfy their gas and electric requirements.

The major elements of the gas industry restructuring are now in place. As discussed in the Regulatory Matters and Natural Gas Matters sections above and in Note 2 of Notes to Consolidated Financial Statements, the Company is responding to recent state and federal regulations that establish the framework for the restructuring of the natural gas industry. The Company no longer has the exclusive responsibility of purchasing gas supplies for customers and will not have exclusive rights to transportation capacity on interstate pipelines. Many customers now have the ability to purchase gas supplies directly from a gas shipper or producer, reserve interstate transportation capacity directly from an interstate pipeline, and then purchase transportation service from the Company once their gas arrives at the California border. An interstate pipeline has proposed expanding its facilities into the Company's service territory, which will allow it to compete directly for transportation service to the Company's noncore customers. In responding to these changing market conditions, the Company is focused on minimizing the cost of gas purchased for its customers and maintaining the competitiveness of its transportation and distribution services within California.

While the restructuring of the electric industry is still evolving, proposals being considered at state and federal levels and the recently enacted National Energy Policy Act of 1992 (Act) will bring more competition into the electric generation business. The Company currently purchases approximately one-third of the electrical power supplied to its customers from qualifying facilities and generation sources outside the Company's service territory. Future additions to satisfy electric supply needs in the Company's service territory will be determined largely through a competitive bidding process, a feature of the new competitive market for electric generation. With its enactment, the Act reduces various restrictions on the operation and ownership of independent power producers and provides them with increased access to electric transmission lines throughout the United States. Regulators now have increased authority to order a utility to transport and deliver, or "wheel," energy for wholesale purchasers or sellers of power. While the Act prohibits FERC-ordered retail wheeling, there is no such prohibition at the state level. If future restructuring were to include retail wheeling whereby customers purchase energy directly from an independent power producer and separately pay the Company to wheel the purchased power, the Company's power generation plants and resources could be subject to competition with other available supply options.

If major customers take advantage of the new competitive energy market and leave the Company's utility system, the Company may find it needs to spread the fixed costs of its production and/or delivery systems over fewer units of sales. Unless such costs are reduced or imposed as transition costs on exiting customers, or other measures are taken, the price per unit will increase and remaining customers will pay higher prices. As prices increase, more customers may find it economically advantageous to turn to other energy suppliers. The Company is uncertain as to what extent the regulators will allow increased costs to be charged to remaining customers.

The Board of Directors (Board) in February 1993 authorized a corporate reorganization and work force management plan, including a voluntary retirement incentive program, as a result of an analysis of areas of gas and electric operations where costs can be controlled or reduced while maintaining high quality service. In conjunction with implementing the work force management plan, the Company filed an application with the CPUC to establish a balancing account through which the labor savings, net of the related costs, would be flowed back to the customers in the form of reduced gas and electric rates. During the three-year 1993 GRC cycle, the Company estimates that the labor savings will more than offset the estimated costs of at least $140 million to be incurred to accomplish the work force reductions.

The Company continues to pursue improvements in the efficiency and productivity of utility operations to keep prices competitive and is positioning itself to meet the challenges of an increasingly competitive business environment.

New Accounting Standards: Statement of Financial Accounting Standards (SFAS) No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, and SFAS No. 109, *Accounting for Income Taxes*, established new financial accounting standards which the Company adopted January 1, 1993. Due to expected future regulatory treatment, adoption of SFAS No. 106 should not have a significant impact on the Company's financial position or results of operations, and adoption of SFAS No. 109 should not have a significant impact on the Company's results of operations. Adoption of SFAS No. 109 resulted in an increase in consolidated assets and liabilities of $1.8 billion as a result of recording additional deferred taxes and the related regulatory asset and increase in plant in service as of January 1, 1993. (See Note 7 of Notes to Consolidated Financial Statements for further discussion of SFAS No. 106.)

Liquidity and Capital Resources

Capital Requirements: The Company's three-year projection of capital requirements is shown below:

(in millions)	Year ended December 31, 1993	1994	1995
Utility	$1,555	$1,667	$1,818
PGT-PG&E Pipeline Expansion Project	669	51	7
Diablo Canyon	118	131	102
Enterprises	163	147	299
Total capital expenditures	2,505	1,996	2,226
Maturing debt and sinking funds	367	297	553
Total capital requirements	$2,872	$2,293	$2,779

Utility expenditures primarily will be for replacing, enhancing and expanding the Company's facilities to improve their efficiency and reliability, to extend their useful life, to comply with environmental laws and regulations and to meet the increasing demands on the system. Utility and pipeline expansion expenditures include the allowance for funds used during construction.

Enterprises' actual capital expenditures may vary significantly depending on the a. " `ility of attractive investment opportunities. These expenditures include oil and gas exploration and development costs and Enterprises' equity share of generating facility projects.

In addition to these capital requirements, the Company has other commitments as discussed in Notes 2 and 9 of Notes to Consolidated Financial Statements.

PGT-PG&E Pipeline Expansion Project: The Company is constructing an expansion of its natural gas transmission system from the Canadian border into California. The aggregate cost of the project is currently forecasted at approximately $1.7 billion. At December 31, 1992 and 1991, the Company's total investment in the project (which is included in construction work in progress) was approximately $979 million and $116 million, respectively. The $979 million at December 31, 1992 consists of $457 million for the facilities within California (i.e., intrastate portion) and $522 million for the facilities outside California (i.e., interstate portion). As discussed in Note 10 of Notes to Consolidat.d Financial Statements, the Company has filed an application with the CPUC to increase the cost cap for the California portion of the project from $736 million to $849 million. The Company believes that the ultimate outcome of the recovery of costs for the project would not have a significant impact on its financial position or results of operations.

Sales and Acquisition: In June 1992, PGT sold its 49.98% interest in ANG to TransCanada for $97 million. The sale resulted in an after-tax gair of $19 million.

The Company and TransCanada had discussions in 1992 regarding the possible sale of PGT to TransCanada, but deferred their discussions regarding the transaction pending resolution of the restructuring of the gas purchase contracts between A&S and Canadian gas producers, as discussed in Note 2 of Notes to Consolidated Financial Statements. The Company has granted TransCanada a limited right of first refusal to acquire PGT. In addition, the Company is assessing its continued ownership of A&S.

In December 1991, PG&E Resources Company, a wholly owned subsidiary of Enterprises, purchased TEX/CON Oil & Gas Company, an oil and gas exploration and production company, for $389 million.

Common Stock Repurchase Program: In 1990, the Board authorized the Company to repurchase $1.25 billion of common stock on the open market or in negotiated transactions, primarily to offset new shares issued through the Company's employee Savings Fund Plan and Dividend Reinvestment Plan. In April 1992, the repurchase program was suspended indefinitely. Through April 1992, the Company repurchased $798 million of its common stock under this authorization, of which $5 million, $338 million and $455 million were repurchased in 1992, 1991 and 1990, respectively. In addition, in 1990, the Company repurchased approximately $60 million of its common stock which was used for the acquisition of a nonregulated business.

Sources of Capital: Internally generated cash flows and external financings will continue to supply capital. The Company's capital structure helps provide financial flexibility and access to capital markets at reasonable rates; 1993 authorized and 1992 and 1991 actual capital structures are summarized in the Rate Proceedings section of Management's Discussion and Analysis.

Debt: In 1992, the Company issued $1,250 million of first and refunding mortgage bonds (series 92A through 92D) and $263 million of medium-term notes. Proceeds were used, in part, to redeem $1,182 million of high-cost mortgage bonds in an effort to reduce financing costs. In addition, procee^ls from these financings were used for the redemption, repayment or retirement of preferred stock and were applied to construction expenditures. In January 1993, the Board authorized the Company to redeem up to $1.2 billion of mortgage bonds to further reduce financing costs.

The Company issues short-term debt (principally commercial paper) for interim construction financing and for fluctuations in general working capital. Short-term debt also has helped fund fuel oil, nuclear fuel and gas inventories, advances to gas producers and unrecovered balances in balancing accounts. The Company must use external financing when balancing account revenues are undercollected, as in 1992 and 1991, until the revenues, plus interest, are received in rates. The Company's short-term borrowings were $1.1 billion at December 31, 1992. At December 31, 1992, the Company had unused credit facilities for short-term borrowings of $381 million.

A $600 million interim financing due December 1993 was closed in January 1993 for PGT's portion of the PGT-PG&E pipeline expansion project and for refinancing PGT's existing pipeline system. The Company is negotiating a long-term credit facility for $750 million in financing that will replace the $600 million interim financing. See Notes 5 and 6 of Notes to Consolidated Financial Statements for further discussion of long- and short-term debt.

Equity: In 1992, the Company received $297 million in proceeds from the sale of common stock under the employee Savings Fund Plan, the Dividend Reinvestment Plan and the employee Stock Option Plan. Proceeds were used to finance additions to utility plant and for other general corporate purposes.

In 1992, the Company issued $200 million of redeemable preferred stock. Proceeds were used to finance a portion of the redemption of $229 million of the Company's high-cost preferred stock in an effort to reduce financing costs. In January 1993, the Board authorized the Company to redeem an additional $267 million of preferred stock. See Note 4 of Notes to Consolidated Financial Statements for further discussion of preferred stock.

Environmental Matters: The Company is subject to an increasing number of laws and regulations designed to protect the environment by imposing stringent controls with regard to planning and construction, land use, air and water pollution and hazardous waste management activities. These laws and regulations affect future planning and existing operations, including environmental protection and cleanup activities.

Environmental Protection: The Company's projected expenditures for environmental protection are subject to periodic review and revision to reflect changing technology and evolving regulatory requirements. Capital expenditures for environmental protection are currently estimated to be approximately $70 million, $100 million and $120 million for 1993, 1994 and 1995, respectively, and are included in the Company's three-year projection table in the above Capital Requirements section. Expenditures during these years will be primarily for nitrogen oxide emission reduction projects. The Company's environmental protection capital expenditures are recovered through rates and the Company anticipates that this will continue.

Environmental Cleanup: The Company assesses, on an ongoing basis, measures that may need to be taken to comply with laws and regulations related to environmental cleanup activities, primarily at retired manufactured gas plant sites. See further discussion of the environmental cleanup liability and related deferred charge in Note 10 of Notes to Consolidated Financial Statements.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Shareholders and the Board of Directors of Pacific Gas and Electric Company:

We have audited the accompanying consolidated balance sheet and the statement of consolidated capitalization of Pacific Gas and Electric Company (a California corporation) and subsidiaries as of December 31, 1992 and 1991, and the related statements of consolidated income, cash flows, common stock equity and preferred stock, and the schedule of consolidated segment information for each of the three years in the period ended December 31, 1992. These financial statements are the responsibility of the Company's management. 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 consolidated financial statements and schedule of consolidated segment information referred to above present fairly, in all material respects, the financial position of Pacific Gas and Electric Company and subsidiaries as of December 31, 1992 and 1991, and the results of their operations and cash flows for each of the three years in the period ended December 31, 1992 in conformity with generally accepted accounting principles.

As discussed in Note 2 of Notes to Consolidated Financial Statements, a number of Canadian gas producers filed lawsuits against the Company for the alleged failure to meet its minimum contractual gas purchase obligations. Revised regulations will require the Company to restructure its gas supply arrangements. The Company believes it is reasonably possible that the ultimate outcome of the litigation and gas contract restructuring will have a significant adverse impact on the Company's financial position or results of operations. However, at this stage in the restructuring process and in view of the uncertainties inherent in litigation and in rate recovery of any transition payments, the Company is unable to estimate the ultimate amount of such financial impact.

As discussed in Note 2 of Notes to Consolidated Financial Statements, the reasonableness of Canadian gas costs for 1988 through 1992 is subject to California Public Utilities Commission review. The Company currently is unable to estimate the ultimate outcome of the reasonableness proceedings or predict whether such outcome will have a significant adverse impact on its financial position or results of operations.

As discussed in Note 10 of Notes to Consolidated Financial Statements, the Company provided a reserve of approximately $64 million against its investment in Helms as a result of an adverse decision in 1990 in the water conduit rupture litigation. The remaining net unrecovered costs and revenues related to Helms are approximately $108 million. The Company is uncertain whether, and to what extent, any of the remaining costs and revenues will be recovered through the ratemaking process.

ARTHUR ANDERSEN & CO.
San Francisco, California
February 1, 1993

RESPONSIBILITY FOR FINANCIAL STATEMENTS

The responsibility for the integrity of the financial information included in this report rests with management. Such information has been prepared in accordance with generally accepted accounting principles appropriate in the circumstances, and is based on the Company's best estimates and judgments after giving consideration to materiality.

The Company maintains systems of internal accounting controls supported by formal policies and procedures which are communicated throughout the Company. These controls are adequate to provide reasonable assurance that assets are safeguarded from material loss or unauthorized use and to produce the records necessary for the preparation of financial information. There are limits inherent in all systems of internal controls, based on the recognition that the costs of such systems should not exceed the benefits to be derived. The Company believes its systems provide this appropriate balance. In addition, the Company's internal auditors perform audits and evaluate the adequacy of and the adherence to these controls, policies and procedures.

Arthur Andersen & Co., the Company's independent public accountants, considered the Company's systems of internal accounting controls and have conducted other tests as they deemed necessary to support their opinion on the consolidated financial statements. Their auditors' report contains an independent informed judgment as to the fairness, in all material respects, of the Company's reported results of operations and financial position.

In a further attempt to assure objectivity and remove bias, the financial data contained in this report have been reviewed by the Audit Committee of the Board of Directors. The Audit Committee is composed of five outside directors who meet regularly with management, the corporate internal auditors and Arthur Andersen & Co., jointly and separately, to review internal accounting controls and auditing and financial reporting matters.

The Company maintains high standards in selecting, training and developing personnel to ensure that management's objectives of maintaining strong, effective internal controls and unbiased, uniform reporting standards are attained. The Company believes its policies and procedures provide reasonable assurance that operations are conducted in conformity with applicable laws and with its commitment to a high standard of business conduct.

CONSOLIDATED FINANCIAL STATEMENTS

Pacific Gas and Electric Company

STATEMENT OF CONSOLIDATED INCOME

(in thousands, except per share amounts)	Year ended December 31, 1992	1991	1990
OPERATING REVENUES			
Electric	$ 7,747,492	$7,368,640	$7,036,071
Gas	2,548,596	2,409,479	2,434,021
Total operating revenues	10,296,088	9,778,119	9,470,092
OPERATING EXPENSES			
Cost of electric energy	2,416,554	2,318,179	2,233,879
Cost of gas	1,062,879	960,208	1,168,464
Distribution	219,082	208,881	195,352
Transmission	184,165	195,642	180,157
Customer accounts and services	421,990	372,088	345,194
Maintenance	484,751	525,220	404,154
Depreciation and decommissioning	1,221,490	1,140,877	1,046,417
Administrative and general	927,316	875,878	794,368
Income taxes	906,845	863,089	856,401
Property and other taxes	295,164	288,610	278,231
Other	322,411	316,368	261,339
Total operating expenses	8,462,647	8,065,040	7,763,956
OPERATING INCOME	1,833,441	1,713,079	1,706,136
OTHER INCOME AND (INCOME DEDUCTIONS)			
Interest income	87,244	94,161	127,375
Allowance for equity funds used during construction	39,368	24,543	24,585
Other—net	(3,006)	(23,909)	(67,023)
Total other income and (income deductions)	123,606	94,795	84,937
INCOME BEFORE INTEREST EXPENSE	1,957,047	1,807,874	1,791,073
INTEREST EXPENSE			
Interest on long-term debt	739,279	697,185	699,849
Other interest charges	91,404	101,871	126,745
Allowance for borrowed funds used during construction	(44,217)	(17,574)	(22,691)
Net interest expense	786,466	781,482	803,903
NET INCOME	1,170,581	1,026,392	987,170
Preferred dividend requirement	78,887	89,595	98,001
EARNINGS AVAILABLE FOR COMMON STOCK	$ 1,091,694	$ 936,797	$ 889,169
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	422,714	417,965	423,759
EARNINGS PER COMMON SHARE	$2.58	$2.24	$2.10
DIVIDENDS DECLARED PER COMMON SHARE	$1.76	$1.64	$1.52

The accompanying Notes to Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

CONSOLIDATED BALANCE SHEET

(in thousands)	December 31, 1992	1991
ASSETS		
PLANT IN SERVICE		
Electric		
Nonnuclear	$ 16,295,567	$15,497,597
Diablo Canyon	5,983,976	5,860,468
Gas	5,454,084	5,073,997
Total plant in service (at original cost)	27,733,627	26,432,062
Accumulated depreciation and decommissioning	(10,507,560)	(9,472,581)
Net plant in service	17,226,067	16,959,481
CONSTRUCTION WORK IN PROGRESS	1,534,578	711,509
OTHER NONCURRENT ASSETS		
Oil and gas properties	591,544	632,811
Decommissioning and other funds held by trustees	456,061	384,369
Advances to gas producers	10,237	46,095
Other assets	368,804	306,384
Total other noncurrent assets	1,426,646	1,369,659
CURRENT ASSETS		
Cash and cash equivalents	97,592	97,280
Accounts receivable		
Customers	1,319,285	1,311,645
Other	156,826	255,468
Allowance for uncollectible accounts	(23,806)	(16,677)
Regulatory balancing accounts receivable	743,253	555,955
Inventories		
Materials and supplies	234,630	225,107
Gas stored underground	151,707	186,861
Fuel oil	155,816	158,725
Nuclear fuel	135,171	99,470
Prepayments	47,809	39,443
Total current assets	3,018,283	2,913,278
DEFERRED CHARGES		
Diablo Canyon costs	260,042	271,115
Environmental cleanup costs	69,899	70,540
Workers' compensation and disability claims recoverable	174,168	140,340
Unamortized loss net of gain on reacquired debt	289,338	245,772
Other	189,138	218,976
Total deferred charges	982,585	946,743
TOTAL ASSETS	$ 24,188,159	$22,900,670

The accompanying Notes to Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

CONSOLIDATED BALANCE SHEET

(in thousands)	December 31, 1992	December 31, 1991
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
Common stock	$ 2,134,228	$ 2,087,859
Additional paid-in capital	3,517,062	3,287,313
Reinvested earnings	2,631,847	2,306,152
Total common stock equity	8,283,137	7,681,324
Preferred stock without mandatory redemption provision	790,791	894,897
Preferred stock with mandatory redemption provision	146,888	92,010
Long-term debt	8,379,060	8,249,300
Total capitalization	17,599,876	16,917,531
OTHER NONCURRENT LIABILITIES		
Customer advances for construction	175,451	185,586
Workers' compensation and disability claims	178,000	142,800
Other	233,242	205,200
Total other noncurrent liabilities	586,693	533,586
CURRENT LIABILITIES		
Short-term borrowings	1,131,124	1,009,911
Long-term debt	353,692	125,411
Preferred stock with mandatory redemption provision	12,622	12,622
Accounts payable		
Trade creditors	529,315	678,352
Other	372,157	325,679
Accrued taxes	237,305	109,062
Deferred income taxes	326,219	276,654
Interest payable	87,975	83,491
Dividends payable	187,721	171,159
Amounts due customers	67,324	102,104
Other	197,605	201,113
Total current liabilities	3,503,059	3,095,558
DEFERRED CREDITS		
Deferred investment tax credits	473,879	497,752
Deferred income taxes	1,780,769	1,642,004
Other	243,883	214,239
Total deferred credits	2,498,531	2,353,995
COMMITMENTS AND CONTINGENCIES (Notes 2, 9, and 10)		
TOTAL CAPITALIZATION AND LIABILITIES	$24,188,159	$22,900,670

Pacific Gas and Electric Company

STATEMENT OF CONSOLIDATED CASH FLOWS

(in thousands)	Year ended December 31, 1992	1991	1990
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,170,581	$ 1,026,392	$ 987,170
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and decommissioning	1,221,490	1,140,877	1,046,417
Amortization	97,922	85,499	76,932
Gain on sale of investment in Alberta Natural Gas Company Ltd	(48,722)	—	—
Deferred income taxes	188,330	78,800	161,326
Allowance for equity funds used during construction	(39,368)	(24,543)	(24,585)
Advances to gas producers	35,858	72,579	104,991
Increase in other noncurrent liabilities	52,480	713	4,681
Increase (decrease) in other deferred credits	33,973	(33,486)	(2,317)
Changes in operating assets and liabilities			
Accounts receivable	39,922	(69,076)	318
Regulatory balancing accounts receivable	(187,298)	202,401	2,588
Accounts payable	(102,559)	172,245	9,211
Accrued taxes	128,243	35,977	55,703
Other working capital	(71,175)	29,344	(6,911)
Other—net	40,360	7,355	(42,942)
Net cash provided by operating activities	2,560,037	2,725,077	2,372,582
CASH FLOWS FROM INVESTING ACTIVITIES			
Construction expenditures	(2,307,318)	(1,753,609)	(1,494,503)
Allowance for borrowed funds used during construction	(44,217)	(17,574)	(22,691)
Purchase of subsidiary	—	(388,662)	—
Additions to oil and gas properties	(143,633)	(117,847)	(139,624)
Proceeds from sale of investment in Alberta Natural Gas Company Ltd	97,251	—	—
Other—net	77,759	33,156	(6,564)
Net cash used by investing activities	(2,320,158)	(2,244,536)	(1,663,382)
CASH FLOWS FROM FINANCING ACTIVITIES			
Common stock issued	296,653	271,482	260,963
Common stock repurchased	(5,410)	(337,969)	(515,028)
Preferred stock issued	195,451	—	—
Preferred stock redeemed	(276,806)	(123,667)	(53,093)
Long-term debt issued	1,676,513	738,649	376,172
Long-term debt matured or reacquired	(1,348,995)	(196,664)	(357,270)
Long-term debt purchased for sinking fund	(60,342)	(66,556)	(54,565)
Short-term debt issued (redeemed)—net	121,213	(14,278)	396,457
Dividends paid	(809,108)	(765,545)	(731,903)
Other—net	(28,736)	10,078	3,496
Net cash used by financing activities	(239,567)	(484,468)	(674,771)
NET CHANGE IN CASH AND CASH EQUIVALENTS	312	(3,927)	34,429
CASH AND CASH EQUIVALENTS AT JANUARY 1	97,280	101,207	66,778
CASH AND CASH EQUIVALENTS AT DECEMBER 31	$ 97,592	$ 97,280	$ 101,207
Supplemental disclosures of cash flow information			
Cash paid for			
Interest (net of amounts capitalized)	$ 694,512	$ 723,968	$ 743,336
Income taxes	682,809	768,097	567,994

The accompanying Notes to Consolidated Financial Statements are an integral part of this statement.

STATEMENT OF CONSOLIDATED COMMON STOCK EQUITY AND PREFERRED STOCK

(in thousands, except shares)	Common Stock	Additional Paid-In Capital	Reinvested Earnings	Total Common Stock Equity	Preferred Stock Without Mandatory Redemption Provision	Preferred Stock With Mandatory Redemption Provision [1]
BALANCE DECEMBER 31, 1989	$2,144,951	$3,121,583	$2,188,859	$7,455,393	$1,010,195	$ 154,755
Net income—1990			987,170	987,170		
Common stock issued (14,255,467 shares)	71,277	249,998		321,275		
Common stock repurchased (23,026,622 shares)	(115,133)	(199,255)	(200,640)	(515,028)		
Preferred stock redeemed (1,301,842 shares)		(1,436)	(178)	(1,614)	(26,234)	(25,245)
Cash dividends declared						
Preferred stock			(98,829)	(98,829)		
Common stock			(643,319)	(643,319)		
Foreign currency translation adjustment			1,164	1,164		
Net change	(43,856)	49,307	45,368	50,819	(26,234)	(25,245)
BALANCE DECEMBER 31, 1990	2,101,095	3,170,890	2,234,227	7,506,212	983,961	129,510
Net income—1991			1,026,392	1,026,392		
Common stock issued (10,263,302 shares)	51,317	220,165		271,482		
Common stock repurchased (12,910,487 shares)	(64,553)	(98,455)	(174,961)	(337,969)		
Preferred stock redeemed (3,811,325 shares)		(5,287)	(4,438)	(9,725)	(89,064)	(24,878)
Cash dividends declared						
Preferred stock			(91,501)	(91,501)		
Common stock			(685,341)	(685,341)		
Foreign currency translation adjustment			1,774	1,774		
Net change	(13,236)	116,423	71,925	175,112	(89,064)	(24,878)
BALANCE DECEMBER 31, 1991	2,087,859	3,287,313	2,306,152	7,681,324	894,897	104,632
Net income—1992			1,170,581	1,170,581		
Common stock issued (9,453,353 shares)	47,267	249,386		296,653		
Common stock repurchased (179,610 shares)	(898)	(2,450)	(2,062)	(5,410)		
Preferred stock issued (8,000,000 shares)		(4,549)		(4,549)	125,000	75,000
Preferred stock redeemed (9,365,449 shares)		(12,638)	(14,940)	(27,578)	(229,106)	(20,122)
Cash dividends declared						
Preferred stock			(81,393)	(81,393)		
Common stock			(744,277)	(744,277)		
Foreign currency translation adjustment			(2,214)	(2,214)		
Net change	46,369	229,749	325,695	601,813	(104,106)	54,878
BALANCE DECEMBER 31, 1992	$2,134,228	$3,517,062	$2,631,847	$8,283,137	$ 790,791	$ 159,510

(1) Includes current portion.

The accompanying Notes to Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

STATEMENT OF CONSOLIDATED CAPITALIZATION

(in thousands, except shares)	December 31, 1992	1991
COMMON STOCK EQUITY		
Common stock, par value $5 per share (authorized 800,000,000 shares, issued and outstanding 426,845,569 and 417,571,826)	$ 2,134,228	$ 2,087,859
Additional paid-in capital	3,517,062	3,287,313
Reinvested earnings	2,631,847	2,306,152
Total common stock equity	8,283,137	7,681,324
PREFERRED STOCK		
Preferred stock without mandatory redemption provision		
Par value $25 per share(1)		
Nonredeemable		
5% to 6%—5,784,825 shares outstanding	144,621	144,621
Redeemable		
4.36% to 8.2%—18,534,959 and 13,534,959 shares outstanding	463,373	338,373
9% to 10.28%—7,311,868 and 16,476,092 shares outstanding	182,797	411,903
Total preferred stock without mandatory redemption provision	790,791	894,897
Preferred stock with mandatory redemption provision		
Par value $25 per share(1)		
6.57%—3,000,000 shares outstanding	75,000	—
Par value $100 per share (authorized 10,000,000 shares)		
9% and 10.17%—845,100 and 1,046,325 shares outstanding	84,510	104,632
Total preferred stock with mandatory redemption provision	159,510	104,632
Less preferred stock with mandatory redemption provision—current portion	12,622	12,622
Preferred stock with mandatory redemption provision in total capitalization	146,888	92,010
Preferred stock in total capitalization	937,679	986,907
LONG-TERM DEBT		
Pacific Gas and Electric Company (PG&E)		
First and refunding mortgage bonds		
Maturity **Interest rates**		
1992-1997 4.25% to 13%	910,898	940,626
1998-2004 5.375% to 9.375%	1,665,677	1,265,677
2005-2011 6.25% to 10.07%	1,151,120	1,582,870
2012-2018 7.5% to 12.75%	175,600	347,632
2019-2025 8% to 10%	2,721,546	2,421,425
Principal amounts outstanding	6,624,841	6,558,230
Unamortized discount net of premium	(103,707)	(92,201)
Total mortgage bonds	6,521,134	6,466,029
Unsecured debentures, 10.81% to 12%, due 1994-2000	221,523	221,538
Pollution control loan agreements, variable rates, due 2008-2016	925,000	925,000
Unsecured medium-term notes, 4.64% to 10.1%, due 1993-2012	847,361	590,850
Unamortized discount related to unsecured medium-term notes	(3,289)	(2,577)
Other long-term debt	26,056	28,002
Total PG&E long-term debt	8,537,785	8,228,842
Long-term debt of subsidiaries	194,967	145,869
Total long-term debt of PG&E and subsidiaries	8,732,752	8,374,711
Less long-term debt—current portion	353,692	125,411
Long-term debt in total capitalization	8,379,060	8,249,300
TOTAL CAPITALIZATION	$17,599,876	$16,917,531

(1) Authorized 75,000,000 shares in total (both with and without mandatory redemption provision).

The accompanying Notes to Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

SCHEDULE OF CONSOLIDATED SEGMENT INFORMATION

(in thousands)	Electric	Gas	Intersegment Eliminations	Total
1992				
Operating revenues	$ 7,747,492	$2,548,596	$ —	$10,296,088
Intersegment revenues (1)	15,150	410,014	(425,164)	—
Total operating revenues	$ 7,762,642	$2,958,610	$(425,164)	$10,296,088
Depreciation and decommissioning	$ 856,124	$ 365,366		$ 1,221,490
Operating income before income taxes (2)	2,308,828	431,458		2,740,286
Construction expenditures (3)	1,124,368	1,266,535		2,390,903
Identifiable assets (3)	$17,649,757	$5,794,786		$23,444,543
Corporate assets				743,616
Total assets at year end				$24,188,159
1991				
Operating revenues	$ 7,368,640	$2,409,479	$ —	$ 9,778,119
Intersegment revenues (1)	15,043	541,963	(557,006)	—
Total operating revenues	$ 7,383,683	$2,951,442	$(557,006)	$ 9,778,119
Depreciation and decommissioning	$ 843,768	$ 297,109		$ 1,140,877
Operating income before income taxes (2)	2,271,571	304,597		2,576,168
Construction expenditures (3)	1,192,570	603,156		1,795,726
Identifiable assets (3)	$17,259,755	$4,947,101		$22,206,856
Corporate assets				693,814
Total assets at year end				$22,900,670
1990				
Operating revenues	$ 7,036,071	$2,434,021	$ —	$ 9,470,092
Intersegment revenues (1)	13,823	734,271	(748,094)	—
Total operating revenues	$ 7,049,894	$3,168,292	$(748,094)	$ 9,470,092
Depreciation and decommissioning	$ 799,214	$ 247,203		$ 1,046,417
Operating income before income taxes (2)	2,288,965	273,572		2,562,537
Construction expenditures (3)	1,079,098	462,681		1,541,779
Identifiable assets (3)	$16,936,713	$4,318,541		$21,255,254
Corporate assets				703,143
Total assets at year end				$21,958,397

(1) Intersegment electric and gas revenues are accounted for at tariff rates prescribed by the CPUC.

(2) Income taxes and general corporate expenses are allocated in accordance with FERC Uniform System of Accounts and requirements of the CPUC. Operating income in the Statement of Consolidated Income is net of income taxes.

(3) Includes an allocation of common plant in service and allowance for funds used during construction.

The accompanying Notes to Consolidated Financial Statements are an integral part of this schedule.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1: Summary of Significant Accounting Policies

Regulation: Pacific Gas and Electric Company (PG&E) is regulated by the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). PG&E's consolidated financial statements reflect the ratemaking policies of these commissions in conformity with generally accepted accounting principles for rate-regulated enterprises. In the Notes to Consolidated Financial Statements, regulated operations other than the Diablo Canyon Nuclear Power Plant (Diablo Canyon) are referred to as the utility.

Principles of Consolidation: The consolidated financial statements include PG&E and its wholly owned and majoity-owned subsidiaries (the Company). All significant intercompany transactions have been eliminated.

Major subsidiaries, all of which are wholly owned, are: Pacific Gas Transmission Company (PGT)—transports natural gas from the U.S./Canadian border to the Company at the California border; Alberta and Southern Gas Co. Ltd. (A&S)—buys gas in Canada and arranges transport to the U.S. border; Pacific Energy Fuels Company—finances the purchase of nuclear fuel through issuance of its commercial paper; PG&E Enterprises (Enterprises)—owns nonregulated subsidiaries of PG&E, including PG&E Resources Company which engages in exploration, development and production of oil and natural gas and PG&E Generating Company which develops independent power projects.

Alberta Natural Gas Company Ltd (ANG), a 49.98%-owned affiliate of PGT, was sold in June 1992. ANG owns and operates a pipeline in British Columbia, which transports natural gas for A&S to the U.S. border. Prior to the sale of ANG, the Company's investment in ANG was accounted for by the equity method of accounting.

Revenues: Revenues are recorded primarily for deliveries of gas and electric energy to customers. These revenues give rise to receivables from a diversified base of customers including residential, commercial and industrial customers in Northern and Central California.

The CPUC has established a mechanism known as balancing accounts which help stabilize the Company's earnings. Specifically, sales balancing accounts accumulate differences between authorized and actual base revenues. Energy cost balancing accounts accumulate differences between actual costs of gas and electric energy and the revenue designated for recovery of such costs. Recovery of gas and electric energy costs through these balancing accounts is subject to a CPUC determination that such costs were incurred reasonably. (See Note 2.) These balancing accounts are recorded to the extent that future rate recovery from customers, or refunds to customers, are probable.

Plant in Service: The costs of plant additions, including replacements of plant retired, are capitalized. Costs include labor, materials, construction overheads and an allowance for funds used during construction (AFUDC). AFUDC is the cost of debt and equity funds used to finance the construction of new facilities. Financing costs of capital additions for Diablo Canyon are calculated under Statement of Financial Accounting Standards (SFAS) No. 34, *Capitalization of Interest Cost*, since Diablo Canyon is not on cost-based ratemaking. (See Note 3.) The original cost of utility plant retired plus removal costs less salvage are charged to accumulated depreciation. Maintenance, repairs and minor replacements and additions are charged to maintenance expense.

Depreciation and Decommissioning: Depreciation of plant in service is computed using a straight-line remaining-life method.

The estimated cost of decommissioning the Company's nuclear power facilities is recovered in base rates through an annual allowance. The estimated total obligation for decommissioning costs is approximately $1 billion in 1992 dollars; this obligation is being recognized ratably over the facilities' lives. This estimate considers the total costs of decommissioning and dismantling plant systems and structures and includes a contingency factor for possible changes in regulatory requirements and waste disposal cost increases.

As of December 31, 1992, $456 million had been accumulated in external trust funds to be used for the decommissioning of the Company's nuclear facilities; a corresponding amount is thus included in accumulated depreciation and decommissioning. Substantially all of these trust funds are invested in debt securities. At December 31, 1992, the estimated fair value of the external trust funds was approximately $475 million based on quoted market prices. Funds may not be released from the external trust funds until authorized by the CPUC.

As required by federal law, the U.S. Department of Energy (DOE) is responsible for the future storage and disposal of spent nuclear fuel. The cost of these activities is funded through a one-tenth of one cent fee on each kilowatthour (kWh) sold by all nuclear power plants. This fee is paid quarterly to the DOE.

Income Taxes: The Company files a consolidated federal income tax return that includes domestic subsidiaries in which its ownership is 80% or more. Income tax expense includes the current and deferred income tax expense resulting from operations during the year. Deferred income tax expense is provided on most of the major timing differences between financial statement and income tax reporting, to the extent permitted for ratemaking purposes. These timing differences are itemized in the deferred tax section of Note 8. Although the tax effects of most major timing differences are deferred, others are recorded currently, consistent with the ratemaking process. Timing differences for which there are no deferred taxes include removal costs and federal tax depreciation on property acquired prior to 1981, depreciation differences for state purposes, percentage repair allowances expensed for tax purposes and certain capitalized overheads expensed for tax purposes. At December 31,1992, the cumulative net pretax amount of these differences was $1.5 billion for federal purposes and $2.0 billion for state purposes. The Company expects to recover the tax effects of these timing differences in future rates. Investment tax credits are deferred and amortized to income over the life of the related property.

Debt Premium, Discount and Related Expense: Long-term debt premium, discount and related expense are amortized over the life of each issue. Gains and losses on reacquired debt allocated to the utility are amortized over the remaining original lives of the debt reacquired, consistent with ratemaking; gains and losses on debt allocated to Diablo Canyon are recognized in income at the time such debt is reacquired.

Oil and Gas Properties: PG&E Resources Company uses the successful-efforts method of accounting for oil and gas properties.

Inventories: Nuclear fuel inventory is stated at the lower of average cost or market. Amortization of fuel in the reactor is based on the amount of energy output.

Other inventories are valued at average cost except for fuel oil, which is valued by the last-in-first-out method.

Statement of Consolidated Cash Flows: Cash and cash equivalents (at cost which approximates market) include special deposits, working funds and short-term investments with original maturities of three months or less.

Noncash investing activities in 1990 include the exchange of the Company's common stock valued at approximately $60 million for the acquisition of a nonregulated business.

Reclassifications: Prior years' amounts in the consolidated financial statements have been reclassified where necessary to conform to the 1992 presentation.

Note 2: Natural Gas Matters

Canadian Natural Gas Purchase Obligations: PG&E purchases Canadian natural gas from PGT, which in turn purchases such gas from A&S. A&S currently has commitments to purchase minimum quantities of natural gas from Canadian producers under various long-term contracts, most of which extend through 2005. Under some of these contracts, A&S is obligated to take a minimum contract quantity which varies based on a number of factors. For the 1992-1993 contract year A&S expects to meet its aggregate minimum contract quantity; however, as discussed below, there were shortfalls in the amount of gas taken by A&S under these contracts in the past and there may be shortfalls in future periods. A&S is authorized to export to the U.S. approximately 374 billion cubic feet per year, or a maximum of approximately 1,127 million cubic feet per day (MMcf/d). The contract prices are renegotiated on an annual basis. The commodity prices for the contract year that began August 1, 1992, range from approximately $1.28 per thousand cubic feet (Mcf) to approximately $1.65 per Mcf for the fixed-price portion of the supply. The prices of the remainder of the supply fluctuate with market conditions. Based on current forecasts, these prices are expected to range from approximately $1.35 per Mcf to approximately $2.05 per Mcf.

State and Federal Regulatory Restructuring: A new gas procurement program, initiated by the CPUC, went into effect in August 1991. During an interim period, currently scheduled to be in effect until capacity brokering is implemented as discussed below, noncore customers (industrial and commercial customers that meet certain size limitations) may choose to negotiate directly with producers for gas supplies which the Company will purchase under existing contractual arrangements for service via the Company's transportation system from Canada and under contracts for service via the Company's southern transmission system. The Canadian portion of this program provides A&S exclusive rights to sell to noncore customers up to 250 MMcf/d of Canadian gas supply. In addition, the Company's electric department may purchase only 65% of its forecasted gas demand from the core portfolio (primarily from A&S) until implementation of the new capacity brokering program. The remainder of the electric department's supply must be purchased under contracts separate from those for the core portfolio.

In November 1991, the CPUC issued a decision adopting a statewide capacity brokering program. The CPUC's capacity brokering program is a way of allocating interstate pipeline capacity whereby noncore customers and other shippers obtain rights to firm interstate pipeline transportation capacity held by the local gas distribution utilities. The

capacity brokering program is scheduled to take effect on each pipeline serving California on a pipeline-by-pipeline basis after FERC's approval of capacity allocation programs for such pipelines. The capacity brokering decision provides for significant changes in the natural gas industry in California, especially regarding access to Canadian gas supplies for noncore customers and the purchasing and transporting of gas for the Company's electric department. In July 1992, the CPUC issued its final implementation rules in the capacity brokering proceeding. Under these rules, the Company will reserve a certain portion of its interstate transportation capacity on PGT's pipeline for core customers. Noncore customers, brokers and shippers, and the Company's electric department can bid for the Company's remaining interstate transportation capacity.

FERC has also taken several actions which will result in substantial changes in its regulations governing the operations and services provided by interstate pipelines. In April 1992, FERC revised its regulations to require interstate pipelines to unbundle sales services from transportation services. The regulations also discontinued existing interstate pipeline capacity brokering programs and instituted an open access capacity allocation program through which existing firm capacity holders will be able to release their unused firm transportation capacity rights to qualified parties. FERC outlined a process for settlement discussions between pipelines and their customers and provided for recovery of prudently incurred and eligible gas supply transition costs with the goal of implementing the new rules by the 1993-1994 winter heating season.

Impact of Regulatory Actions on Gas Supply Arrangements: The CPUC's gas procurement and capacity brokering programs and FERC's new regulatory structure, when implemented, will result in a decrease in the volume of Canadian gas purchased by the Company. The Company's gas supply requirements will decrease since the Company will no longer provide procurement services for many noncore customers. Under the new rules, the Company's electric department will not have a preference to the Company's firm interstate capacity, as compared to other noncore customers. However, the program provides for a transition period during which the electric department will be permitted to elect core subscription service for up to certain decreasing percentages of its average annual loads. Beginning in the fifth year of the program, the electric department will not be allowed to purchase core subscription service, and instead will compete with other noncore customers to obtain transportation services for all of its gas requirements on the interstate pipelines.

Natural Gas Purchase Contracts Litigation: During 1991 and 1992, a number of Canadian gas producers filed lawsuits against the Company claiming damages of at least $466 million (Canadian) resulting from the alleged failure of A&S to meet its minimum contractual gas purchase obligations for the 1989-1992 contract years, and certain producers seek damages (of at least $245 million (Canadian), which are included in the $466 million above) for the anticipated failure of A&S to meet those obligations through 2005. A significant portion of these claims relate to the 1990-1991 contract year, and the shortfall associated with these producers' supply contracts represents approximately 73% of the total 1990-1991 contract year shortfall resulting from the aggregate A&S gas purchase obligations discussed above. It is possible that other gas producers will pursue similar claims for past and prospective damages.

Proposed Restructuring Plan: In light of the regulatory changes and litigation discussed above, negotiations are being conducted to restructure A&S' contracts with Canadian gas producers. In December 1992, A&S, PGT and PG&E proposed a restructuring plan to approximately 190 gas producers to reduce present obligations, settle litigation and enter into new contracts for future gas supply. The proposed plan includes provisions for a transition period during which existing arrangements will continue until July 31, 1994; options for new long-term gas marketing arrangements between the Company and A&S gas producers effective August 1, 1994; the resolution of claims against A&S, PGT and PG&E that may arise out of existing arrangements; and cash settlement payments to each A&S gas producer that participates in the restructuring plan. The Company proposes to purchase on a long-term basis up to approximately 425 MMcf/d for its core market requirement and up to approximately 205 MMcf/d for its electric department. The planned effective date for the restructured gas arrangements is August 1, 1994. The effectiveness of the restructuring plan is conditioned upon a number of U.S. and Canadian regulatory approvals.

In January 1993, pursuant to the restructuring plan, the Company offered to pay A&S gas producers a total of approximately $150 million to settle any claims they may have against A&S, PGT and PG&E that result from the restructuring of existing arrangements as well as any claims for losses arising from alleged historical shortfalls in gas taken by A&S. Transition payments are conditioned upon the A&S producers' acceptance of the restructuring plan and the satisfaction of various conditions of effectiveness to the plan. The restructuring plan specifies that the Company's shareholders will absorb not less than 15% nor greater than 30% of the transition payments.

In December 1992, PGT filed with FERC its proposal to comply with the restructuring regulations, including recovery of transition payments relating to restructuring its gas supply. PG&E and the CPUC have agreed on transition cost recovery mechanisms for Canadian gas supply transition payments to be proposed in PGT's gas restructuring proceeding at FERC. In return for the CPUC waiving various objections relating to the eligibility and prudence of such payments, both the CPUC and the Company would

support a mechanism at FERC which would require PGT to absorb and not recover from its customers a portion of the transition payments up to a maximum of 27%. As an alternative, the agreement provides that the parties would support PGT, at its discretion, to recover the transition payments through a mechanism whereby 25% of such payments would be absorbed by PGT, 25% would be recovered through direct bills and 50% would be recovered through volumetric surcharges.

Either PG&E or the CPUC may terminate the agreement on a transition cost recovery mechanism if it is materially and adversely modified by FERC. In addition, PG&E may terminate the agreement if it determines that the CPUC will not provide a state ratemaking mechanism that authorizes recovery of all or substantially all transition payments authorized for recovery by FERC.

The actual amount absorbed by PGT under this mechanism will ultimately depend on the level of compensation paid to restructure the Canadian gas supply, the transition cost recovery mechanism adopted by FERC and other factors. Because the transition cost recovery mechanism would affect a number of other parties, the Company cannot predict at this time whether this proposal will be adopted by FERC.

Financial Impact of Litigation and Proposed Restructuring Plan: The financial impact will depend on the amount of the transition payments and the recovery mechanisms adopted by FERC and the CPUC, and other factors. The Company believes it is reasonably possible that the ultimate outcome of the litigation and gas contract restructuring will have a significant adverse impact on the Company's financial position or results of operations. However, at this stage in the restructuring process and in view of the uncertainties inherent in litigation and in rate recovery of any transition payments, the Company is unable to estimate the ultimate amount of such financial impact.

Reasonableness Proceedings: Recovery of gas and electric energy costs through the Company's regulatory balancing account mechanisms is subject to a CPUC determination that such costs were incurred reasonably. Under the current regulatory framework, annual reasonableness proceedings are conducted by the CPUC on a historic calendar year basis.

In July 1991, the CPUC issued a decision which concluded that the electric system operations of the Company were reasonable in 1989, but deferred consideration of the reasonableness of gas system costs and certain gas-related electric system costs. In an earlier decision affecting 1988, the CPUC deferred consideration of the reasonableness of all gas system costs pending completion of an investigation by the CPUC's Division of Ratepayer Advocates (DRA) of the Company's gas procurement activities. Those issues have been consolidated with the CPUC's review of the reasonableness of gas and electric system costs for 1989 and 1990.

In September 1991, the DRA issued its report on the Canadian gas procurement activities during 1988 through 1990. The DRA recommended that the Company refund approximately $410 million based on its contention that the Company should have purchased 50% of its Canadian supplies on the spot market instead of through almost totally relying on long-term contracts. The DRA also noted that the Company purchased electric energy when it was cheaper than its incremental fossil generation costs, which the DRA argued would have been lower if cheaper Canadian gas supplies had been used. The DRA indicated that it did not address at that time issues related to certain contracts with Southwestern gas producers. Using a different theory than the DRA, an intervenor has asserted that the Company overpaid for Canadian gas in the range of $540 million to $670 million.

In addition, the DRA recommended a disallowance of $37 million related to gas inventory operations. The DRA contended that the Company should have withdrawn excess gas from storage in the winter of 1989-1990 and December 1990 rather than burning fuel oil, which on an accounting basis was more expensive.

A decision is expected by mid-1993 in the reasonableness proceeding covering the Company's Canadian gas procurement activities for 1988 through 1990. Hearings on the recommended disallowance of $37 million related to gas inventory operations will be consolidated with the reasonableness review for 1991.

In September 1992, the Company filed testimony to establish the reasonableness of its gas procurement and operating activities for 1991. It is possible that similar issues will be raised regarding the Company's Canadian gas procurement activities during 1991, 1992 and until such time that the Canadian gas supply arrangements are restructured.

The DRA is a consumer advocacy branch of the CPUC staff, and its recommendations do not constitute a CPUC decision. The CPUC can accept all, part or none of the DRA's recommendations. The Company believes that its gas procurement activities were prudent and will vigorously contest any disallowances proposed by the DRA or any other parties.

The Company currently is unable to estimate the ultimate outcome of the reasonableness proceedings or predict whether such outcome will have a significant adverse impact on its financial position or results of operations.

Note 3: Diablo Canyon

Rate Case Settlement: The Diablo Canyon rate case settlement, effective July 1988, bases revenues primarily on the amount of electricity generated by the plant, rather than on traditional cost-based ratemaking. In approving the

settlement, the CPUC explicitly affirmed that Diablo Canyon costs and operations no longer should be subject to CPUC reasonableness reviews. The CPUC cannot bind future commissions in fixing just and reasonable rates for Diablo Canyon, but to the extent permitted by law intends that this decision remain in effect for the full term of the settlement, ending 2016.

The settlement provides that certain Diablo Canyon costs will be recovered over the term of the settlement, including a full return on such costs, through base rates. The related revenues to recover these costs are included in Diablo Canyon operating revenues for reporting purposes. Other than these and decommissioning costs, Diablo Canyon no longer meets the criteria for application of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. Consequently, application of this statement was discontinued for Diablo Canyon effective July 1988.

Pricing: Under the Diablo Canyon rate case settlement, the price per kWh of electricity generated by Diablo Canyon consists of a fixed and an escalating component. The total prices for 1990 through 1992 were 8.93 cents, 9.60 cents and 10.34 cents per kWh, respectively, effective January 1. Total prices for 1993 and 1994, effective January 1 of each year, are 11.16 cents and 11.89 cents per kWh, respectively. For 1995 through 2016, the escalating component will be adjusted by a factor related to inflation. During the first 700 hours of full-power operation for each unit during the peak period (10 a.m. to 10 p.m. on weekdays in June through September), the price is 130% of the stated amount to encourage the Company to utilize the plant during the peak period. Beginning in January of each year, during the first 700 hours of full-power operation for each unit outside the peak period, the price is 70% of the stated amount. At all other times, the price is 100% of the stated amount.

Financial Information: Selected financial information for Diablo Canyon is shown below:

	Year ended December 31,		
(in millions)	**1992**	**1991**	**1990**
Operating revenues	$1,781	$1,501	$1,509
Operating income	663	497	550
Net income	443	274	318

In determining operating results of Diablo Canyon, operating revenues were specifically identified pursuant to the Diablo Canyon rate case settlement. The majority of operating expenses were also specifically identified, including income tax expense, which is calculated based on the pre-tax income of Diablo Canyon. Administrative and general expenses, principally labor costs, are allocated based on actual time incurred or historical trends of labor costs. Interest is charged based on an allocation of corporate debt to Diablo Canyon.

Note 4: Preferred Stock

Nonredeemable preferred stock ($25 par value) consists of a 5%, 5.5% and 6% series, which have rights to annual dividends per share of $1.25, $1.375 and $1.50, respectively.

Redeemable preferred stock without mandatory redemption provision ($25 par value) is subject to redemption, in whole or in part, if the Company pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. Per share information for this type of preferred stock outstanding at December 31, 1992 is:

Series	Annual Dividend	Redemption Price
4.36% to 8.2%	$1.09 to $2.05	$25.00 to $28.125
9% to 9.48%	$2.25 to $2.37	$27.75 to $28.125

Preferred stock with mandatory redemption provision consists of a 9% and 10.17% series ($100 par value) and a 6.57% series ($25 par value), each entitled to a sinking fund providing for the retirement of stock outstanding at par value per share plus accumulated and unpaid dividends through the redemption date. The total mandatory redemption cost, excluding any accumulated and unpaid dividends, for each of the years 1993 through 1997 is $13 million. In addition to mandatory redemptions, this stock may be redeemed at the Company's option at par value per share plus accumulated and unpaid dividends through the redemption date and a redemption premium under specified circumstances. The 9% series is currently redeemable at the Company's option, the 10.17% series is redeemable after August 1993 and the 6.57% series is redeemable after July 2002. The estimated fair value for the Company's total preferred stock with mandatory redemption provision of $160 million at December 31, 1992 was approximately $168 million based primarily on quoted market prices.

During 1992, the Company issued $125 million of 7.44% redeemable preferred stock and $75 million of 6.57% preferred stock with mandatory redemption provision. Proceeds were used to finance a portion of the 1992 redemption of all the Company's 10.28%, 10.18% and 9.28% redeemable preferred stock with an aggregate par value of $229 million.

Dividends on preferred stock are cumulative. Preferred dividends are accrued based on declaration date, whereas preferred dividend requirement, which is used to calculate earnings per common share, is based on the accumulated dividends on preferred stock outstanding during the year. All shares of preferred stock have equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Company, holders of the preferred stock would receive the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series.

Note 5: Long-term Debt

Mortgage Bonds: The first and refunding mortgage bonds of the Company are issued in series, bear annual interest rates ranging from 4.25% to 13% and mature from 1993 to 2025. Additional bonds may be issued, subject to CPUC approval, up to a maximum total outstanding of $10 billion, assuming compliance with indenture covenants for earnings coverage and property available as security. The Company's Board of Directors may increase the amount authorized, subject to CPUC approval. The Company had $6.6 billion of mortgage bonds outstanding at December 31, 1992 and 1991. The indenture requires that net earnings not including depreciation and interest be equal to or greater than 1.75 times the annual interest charges on the Company's mortgage bonds outstanding. All real properties and substantially all personal properties are subject to the lien of the indenture.

The Company is required by the indenture to make semiannual sinking fund payments on February 1 and August 1 of each year for the retirement of the bonds. The payments equal .5% of the aggregate bonded indebtedness outstanding on the preceding November 30 and May 31, respectively. Bonds of any series, with certain exceptions, may be used to satisfy this requirement. In addition, holders of Series 84D bonds maturing in 2017 have an option to redeem their bonds in 1995.

In conjunction with the Company's focus on reducing the levels of high-cost debt, the Company redeemed $1,182 million and $119 million of high-cost mortgage bonds in 1992 and 1991, respectively. Interest rates on the bonds redeemed ranged from 9.125% to 12%.

During 1992, the Company issued $1,250 million of first and refunding mortgage bonds, series 92A through 92D, with interest rates ranging from 7.875% to 8.375% and maturity dates ranging from 2002 to 2025. Proceeds from these bonds were used to redeem high-cost mortgage bonds and preferred stock as well as being applied to construction expenditures.

Included in the total of outstanding mortgage bonds are first and refunding mortgage bonds issued by the Company to secure its obligation to repay various loans from the California Pollution Control Financing Authority (CPCFA) to finance air and water pollution control, and sewage and solid waste disposal facilities. The amounts loaned to the Company by the CPCFA consist of proceeds from the CPCFA's sale of tax-exempt pollution control revenue bonds having the same principal amounts and terms as the Company's mortgage bonds securing the loans. At December 31, 1992 and 1991, the Company had outstanding $508 million and $423 million, respectively, of mortgage bonds securing loans from the CPCFA. These mortgage bonds have interest rates ranging from 6.25% to 8.875% and maturity dates from 2007 to 2018.

Pollution Control Loan Agreements: In addition to the pollution control loans secured by the Company's mortgage bonds (described above), the Company had loans totalling $925 million at December 31, 1992 and 1991 from the CPCFA to finance air and water pollution control, and sewage and solid waste disposal facilities. Interest rates on the loans vary depending on whether the loans are in a daily, weekly, commercial paper or fixed rate mode. Conversions from one mode to another take place at the Company's option. Average annual interest rates on these loans for 1992 ranged from 2.79% to 3.04%. These loans are subject to redemption by the holder on demand under certain circumstances. The Company's obligations for such demands are secured by irrevocable letters of credit which can be drawn on at any time until 1997. Any borrowings resulting from use of the letters of credit would mature in 1997.

Medium-term Notes: The Company had $847 million and $591 million of unsecured medium-term notes outstanding at December 31, 1992 and 1991, respectively, with interest rates ranging from 4.64% to 10.10% and maturities from 1993 to 2012. During 1992 and 1991, the Company issued $263 million and $352 million of medium-term notes, respectively. Proceeds from these notes were applied to construction expenditures and to the redemption, repayment or retirement of debt or preferred stock.

Repayment Schedule: At December 31, 1992, the Company's combined aggregate amount of long-term debt maturing and sinking fund requirements, for the years 1993 through 1997, are $354 million, $284 million, $540 million, $431 million and $386 million, respectively.

Fair Value: The estimated fair value for the Company's total long-term debt of $8.7 billion at December 31, 1992 was approximately $9.2 billion. The estimated fair value of long-term debt was determined based on quoted market prices, where available. Where quoted market prices were not available, the estimated fair value was determined using other valuation techniques (e.g., matrix pricing models or the present value of future cash flows). As discussed in Note 1, gains and losses on reacquired debt allocated to the utility are amortized over the remaining original lives of debt reacquired, consistent with ratemaking; gains and losses on debt allocated to Diablo Canyon are recognized in income at the time such debt is reacquired. Debt allocated to Diablo Canyon at December 31, 1992 had a book value of $2.2 billion and a fair value of approximately $2.3 billion.

Note 6: Short-term Borrowings

Short-term borrowings are mostly commercial paper with a weighted average interest rate of 3.72% at December 31, 1992. The usual maturity for commercial paper is 10 to 90

days. Commercial paper outstanding at December 31, 1992 and 1991 was $916 million and $833 million, respectively. The carrying amount of short-term borrowings approximates fair value.

The Company has $1.3 billion in revolving credit facilities with various banks to support the sale of commercial paper and for other corporate purposes. At December 31, 1992 and 1991, there were no borrowings outstanding under these facilities. The amount available under these facilities is reduced to the extent of outstanding commercial paper balances. These credit facilities expire through 1994; however, they may be extended annually for additional one-year periods upon mutual agreement between the Company and the banks. The Company is in compliance with all covenants associated with the facilities.

A $600 million interim financing due December 1993 was closed in January 1993 for PGT's portion of the PGT-PG&E pipeline expansion project and for refinancing PGT's existing pipeline system. The Company is negotiating a long-term credit facility for $750 million in financing that will replace the $600 million interim financing.

Note 7: Employee Benefit Plans

Retirement Plan: The Company provides a noncontributory defined benefit pension plan covering substantially all employees. The retirement benefits are based on years of service and the employee's base salary. The Company's funding policy is to contribute each year not more than the maximum amount deductible for federal income tax purposes and not less than the minimum contribution required under the Employee Retirement Income Security Act of 1974. The cost of this plan is charged to expense and to plant in service through construction work in progress.

Net pension cost, using the projected unit credit actuarial cost method, was:

	Year ended December 31,		
(in thousands)	**1992**	**1991**	**1990**
Service cost for benefits earned	$ 127,388	$112,940	$112,552
Interest cost on projected benefit obligation	248,674	238,153	232,263
Actual loss (return) on plan assets	(204,576)	(774,445)	65,205
Net amortization and deferral	(78,560)	552,775	(292,147)
Net pension cost (including amounts capitalized)	$ 92,926	$129,423	$115,873

The decrease in net pension cost in 1992 compared to 1991 was mostly due to favorable investment returns in 1991. The increase in net pension cost in 1991 compared to 1990 was due in part to a plan amendment made by the Company at year end 1990.

Net pension cost is calculated using expected return on plan assets. The difference between actual and expected return on plan assets is included in net amortization and deferral and is considered in the determination of future pension cost.

In 1992, actual return on plan assets was less than expected return whereas, in 1991, actual return on plan assets exceeded expected return. In 1990, the plan experienced a negative investment return on plan assets.

The expected long-term rate of return on plan assets used in determining pension cost was 8% for 1992, 1991 and 1990.

In conformity with accounting for rate-regulated enterprises, regulatory adjustments have been recorded in the income statement and balance sheet for the difference between utility pension cost determined for accounting purposes and that for ratemaking, which is based on a contribution approach.

The plan's funded status was:

	December 31,	
(in thousands)	**1992**	**1991**
Actuarial present value of projected benefit obligations		
Vested benefits	$2,680,364	$2,530,262
Nonvested benefits	183,971	174,143
Accumulated benefit obligation	2,864,335	2,704,405
Effect of projected future compensation increases	859,764	808,219
Projected benefit obligation	3,724,099	3,512,624
Plan assets at market value	3,872,374	3,728,174
Plan assets in excess of projected benefit obligation	(148,275)	(215,550)
Unrecognized prior service cost	(71,324)	(76,432)
Unrecognized net gain	383,498	507,889
Unrecognized net obligation	(137,763)	(149,743)
Accrued pension liability	$ 26,136	$ 66,164

Plan assets are composed primarily of common stocks, fixed-income securities and real estate investments. The unrecognized prior service cost is being amortized over approximately 16 years, beginning in 1991. The unrecognized net obligation is being amortized over approximately 18 years, beginning in 1987.

Assumptions used to calculate the projected benefit obligation to determine the plan's funded status were:

	Year ended December 31,	
	1992	**1991**
Weighted average discount rate	7%	7%
Average rate of projected future compensation increases	6%	6%

Savings Fund Plan: The Company sponsors a defined contribution pension plan to which employees with at least one year of service may make contributions. Employees may contribute up to 14 percent of their covered compensation on a pretax or after-tax basis. Pretax employee contributions and, effective January 1991, after-tax employee contributions, up to a maximum of six percent of covered compensation, are eligible for matching Company contributions at specified rates. The cost of Company contributions was charged to expense and to plant in service through

construction work in progress and totalled $35 million, $33 million and $30 million for 1992, 1991 and 1990, respectively.

Long-Term Incentive Program: In 1992, the Company implemented a Long-Term Incentive Program (Program). The Program allows eligible participants to be granted stock options with or without associated stock appreciation rights, dividend equivalents and/or performance-based units. The Program incorporates those shares previously authorized under the Company's 1986 Stock Option Plan.

A total of 14.5 million shares of common stock have been authorized for award under the Program and the 1986 Stock Option Plan. Costs associated with the Program, which have not been significant, are not recoverable in rates.

At December 31, 1992, stock options on 1,544,839 shares, granted at option prices ranging from $16.75 to $32.13, were outstanding. During 1992, 669,450 options were granted at an option price of $32.13. Option prices are the market price per share on the date of grant.

Outstanding stock options expire ten years and one day after the date of grant and become exercisable on a cumulative basis at one-third each year commencing two years from the date of grant. Stock options also become exercisable within certain time limitations upon the optionee's termination due to retirement, disability, death or a change in control of a subsidiary; and upon certain changes in control of the Company.

In 1992, stock options on 157,446 shares were exercised at option prices ranging from $16.75 to $26.63. At December 31, 1992, stock options on 171,918 shares were exercisable.

Postretirement Benefits Other Than Pensions: The Company provides a contributory defined benefit medical plan for retired employees and their eligible dependents and a noncontributory defined benefit life insurance plan for retired employees. Substantially all employees retiring at or after age 55 are eligible for these benefits. The medical benefits are provided through plans administered by an insurance carrier or a health maintenance organization. Certain retirees are responsible for a portion of the cost based on past claims experience of the Company's retirees. The Company's funding policy for the medical and life insurance benefits is to contribute each year the tax-deductible amount provided for in rates. Life insurance benefits which are not funded are provided through an insurance company at a cost based on total current claims paid plus administrative fees.

The cost of postretirement medical benefits, based on benefits paid and funded, totalled $95 million, $89 million and $16 million for 1992, 1991 and 1990, respectively. The cost of providing postretirement life insurance benefits totalled $3 million for each of the years 1992, 1991 and 1990. These costs were charged to expense and to plant in service through construction work in progress.

SFAS No. 106: Effective January 1, 1993, the Company adopted SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions,* which requires accrual of the expected cost of these benefits during the employees' years of service. The assumptions and calculations involved in determining the accrual closely parallel pension accounting requirements. The Company previously recognized these costs as benefits were paid or funded, which was consistent with ratemaking.

In accordance with SFAS No. 106, the Company has elected to amortize the actuarially-determined transition obligation of $1,018 million over 20 years beginning in 1993. The amortization will be a component of the annual postretirement benefit cost, which cost for 1993 is estimated to total approximately $170 million, using the projected unit credit actuarial cost method.

The actuarial assumptions used to determine the benefit obligations and costs for postretirement benefits other than pensions include a weighted average discount rate of 7%, weighted average expected long-term rate of return on plan assets of 7.7% and a rate of increase in future compensation levels of 6%. The assumed health care cost trend rate in 1993 is approximately 12%, grading down to an ultimate rate in 2005 of approximately 6%. The effect of a one-percentage-point increase in the assumed health care cost trend rate would increase the accumulated postretirement benefit obligation at January 1, 1993 by approximately $205 million and the annual aggregate service and interest costs by approximately $30 million.

The medical and life insurance plans' funded status as of January 1, 1993 was:

(in thousands)	**January 1, 1993**
Accumulated postretirement benefit obligation	
Retirees	$ 328,976
Fully eligible active participants	182,731
Other active plan participants	703,748
	1,215,455
Plan assets at market value	208,261
Accumulated postretirement benefit obligation in excess of plan assets	1,007,194
Unrecognized transition obligation	(1,018,402)
Prepaid postretirement benefit	$ (11,208)

The Company and other California utilities have been participating in an investigation before the CPUC on the ratemaking effects of the new accounting standard on regulated utilities. In July 1991, the CPUC authorized rate recovery of tax-deductible funding for postretirement medical benefits in 1991 and 1992. (The Company has historically received rate recovery to fund certain postretirement life insurance benefits.) Consistent with this authorization, the Company made an aggregate contribution of approximately $168 million in 1991 and 1992 to two independent trusts

established to hold amounts collected in rates for payment of postretirement medical benefits. Assets held in the trusts consist mainly of short-term fixed-income securities.

In December 1992, the CPUC issued a decision in the final phase of the investigation on the ratemaking treatment for these benefits in 1993 and beyond. The decision authorized recovery of revenue requirements to fund these benefits, within certain guidelines, at a level equal to the lesser of the annual SFAS No. 106 expense, based on amortization of the transition obligation over 20 years, or the amount which can be contributed annually on a tax-deductible basis to appropriate trusts. The annual difference between the utility SFAS No. 106 expense and the revenue requirement is not expected to be significant. Therefore, adoption of SFAS No. 106 should not have a significant impact on the Company's financial position or results of operations.

Note 8: Income Taxes

The current and deferred components of income tax expense were:

(in thousands)	Year ended December 31, 1992	1991	1990
Current			
Federal	$536,774	$589,713	$555,186
State	193,895	201,445	185,015
Total current	730,669	791,158	740,201
Deferred (substantially all federal)			
Regulatory balancing accounts	85,210	(86,682)	(11,031)
Depreciation	165,944	161,937	191,899
Other—net	(62,824)	3,545	(19,542)
Total deferred	188,330	78,800	161,326
Investment tax credits—net	(23,873)	(18,424)	(19,880)
Total income tax expense	$895,126	$851,534	$881,647
Classification of income taxes			
Included in operating expenses	$906,845	$863,089	$856,401
Included in other—net	(11,719)	(11,555)	25,246
Total income tax expense	$895,126	$851,534	$881,647

The differences between reported income taxes and amounts determined on income before income tax expense by applying the federal statutory rate of 34% were:

(in thousands)	Year ended December 31, 1992	1991	1990
Expected federal income tax expense at statutory rate	$ 702,340	$ 638,495	$ 635,398
Increase (decrease) in income tax expense resulting from			
Investment tax credits	(23,873)	(18,424)	(19,880)
State income tax (net of federal benefit)	125,906	134,568	173,206
Depreciation and related timing differences not deferred	103,613	101,098	95,678
Other—net	(12,860)	(4,203)	(2,755)
Total income tax expense	$ 895,126	$ 851,534	$ 881,647
Income before income tax expense	$2,065,707	$1,877,926	$1,868,817
Effective tax rate (total income tax expense/income before income tax expense)	43.3%	45.3%	47.2%

SFAS No. 109: Effective January 1, 1993, the Company adopted SFAS No. 109, *Accounting for Income Taxes*, which established new financial accounting standards for income taxes. The effect of the new standard was an [illegible]se in consolidated assets and liabilities of $1.8 billion [illegible]sult of recording additional deferred taxes and the [illegible] regulatory asset and increase in plant in service as of January 1, 1993. Due to expected future regulatory treatment, adoption of SFAS No. 109 should not have a significant impact on the Company's results of operations.

Note 9: Commitments

Capital Projects: Capital expenditures for 1993 are estimated to be approximately $2,505 million, consisting of $1,555 million for utility expenditures, $669 million for the PGT-PG&E pipeline expansion project, $118 million for Diablo Canyon and $163 million for nonregulated expenditures. Utility and pipeline expansion expenditures include AFUDC.

At December 31, 1992, Enterprises had commitments totalling $200 million to make capital contributions for its equity share of generating facility projects. The contributions, payable upon commercial operation of the projects, are estimated to be $36 million in 1993 (which is included in the amounts in the preceding paragraph), $50 million in 1994, $100 million in 1995, none in 1996 and 1997, and $14 million thereafter.

Qualifying Facilities (QFs): Under the Public Utility Regulatory Policies Act of 1978, the Company is required to purchase electric energy and capacity produced by QFs. The CPUC established a series of power purchase agreements which set the applicable terms, conditions and price options. The QF must meet certain performance obligations, depending on the contract, prior to receiving capacity payments. The total cost of both energy and capacity payments to QFs is recoverable in rates. The Company's contracts with QFs expire on various dates from 1993 to 2021. Under these contracts, the Company is required to make payments only when energy is supplied or when capacity commitments are met. Payments to QFs are expected to vary in future years. There are no requirements to make debt service payments. QF deliveries in the aggregate account for approximately 25% of the Company's 1992 total electric energy requirements and no single contract accounts for more than 5% of the Company's energy needs. QF deliveries in 1992 represented approximately 87% of the QFs' plant output, in the aggregate. The amount of energy received from QFs and the total energy and capacity payments made under these agreements were:

(in millions)	Year ended December 31, 1992	1991	1990
Kilowatthours received	21,173	19,127	17,010
Energy payments	$1,086	$970	$873
Capacity payments	$ 489	$450	$374

Irrigation Districts and Water Agencies: The Company has contracts with various irrigation districts and water agencies to purchase hydroelectric power. The contracts expire on various dates from 2004 to 2031. Under these contracts, the Company must make specified monthly or semi-annual minimum payments whether or not any energy is supplied, subject to the provider's retention of FERC authorization. Additional variable payments for operation and maintenance costs incurred by the providers also are required to be made under the contracts. The total cost of these payments is recoverable in rates. At December 31, 1992, the future minimum payments under these contracts were $33 million for each of the years 1993 through 1997 and a total of $511 million for periods thereafter. Total payments under these contracts were $54 million, $47 million and $45 million in 1992, 1991 and 1990, respectively.

Western Area Power Administration (WAPA) Energy Agreement: The Company has an agreement with WAPA to purchase energy from them and resell it to them upon their request. The energy under contract has been purchased by the Company from WAPA at favorable prices based on WAPA's cost of generation. That energy must be sold back to WAPA at a price equal to the Company's current thermal production cost at the time of delivery to WAPA less the Company's savings that resulted from the purchases at the lower WAPA prices.

The contract will expire in 2005. At December 31, 1992, the cost to the Company to return the amount of energy currently available to WAPA was approximately $209 million, assuming WAPA requests the return of all the energy prior to the contract's expiration date. However, such cost represents a return of the benefits the Company received through its purchases from WAPA, which were passed on to ratepayers at that time. The Company believes it is entitled to recover in rates costs of energy resold to WAPA.

Gas Demand and Reservation Charges: The Company has gas purchase and transportation service agreements with various interstate pipelines and upstream pipeline systems in Canada. These pipeline service agreements include provisions for fixed demand or reservation charges for providing the contracted level of service. The aggregate annual demand and reservation payments under the contracts in effect as of December 31, 1992, the longest of which extends through 2007, are approximately $250 million. The Company is required to pay additional amounts depending on actual quantities transported under these agreements. The Company's total demand, reservation and transportation charges paid under these agreements were approximately $300 million, $260 million and $275 million in 1992, 1991 and 1990, respectively.

As a result of the new capacity allocation regulations discussed in Note 2, the amount paid for pipeline demand or reservation charges will increase due to changes in rate design method; however, the charges may decrease due to the Company's relinquishment or temporary release of capacity on the interstate pipelines.

Note 10: Contingencies

Helms Pumped Storage Plant (Helms): The completion of Helms was delayed due to a water conduit rupture in 1982 and various start-up problems related to the plant's generators. Helms became commercially operable in 1984.

The total cost of the plant at December 31, 1992 was $967 million, of which $769 million has been allowed in rate base and $22 million was disallowed by the CPUC in 1985. In 1990, as a result of an adverse decision in the litigation with USX Corporation in which the jury found that the Company's negligence was the proximate cause of the water conduit rupture, the Company reserved approximately $64 million for the costs (after adjustment for depreciation) attributable to the conduit rupture.

The Company sought recovery of the majority of the remaining costs attributable to the problems with the generators through litigation with Westinghouse Electric Corporation (Westinghouse). The Company also sought from Westinghouse recovery of the revenues lost during the time that Helms was out of service for the modification and repair of the generators. These revenues and related recorded interest amounted to $55 million, all of which had been recorded as a balancing account receivable in prior years. In 1991, the Company and Westinghouse entered into a comprehensive settlement agreement to resolve the Helms litigation. Under the terms of the agreement, Westinghouse agreed to reduce the cost of goods and services purchased in the future by credits with a net present value of $30 million.

The remaining unrecovered costs of Helms (after adjustment for depreciation) and revenues discussed above totalled $108 million at December 31, 1992. The Company has filed an application for rate recovery of the remaining unrecovered Helms costs, the associated revenue requirement on such costs for 1984 through 1992 and lost revenues during the time the generators were being repaired. The DRA's report on the Company's application is expected in 1993.

The CPUC indicated in a 1985 rate decision that should the Company seek recovery in rates of expenditures related to the problems with the plant's generators, it will bear a heavy burden of proof in establishing their reasonableness. The CPUC also declined in 1985 to include in rates the revenues recorded during the time Helms was out of service for the modification and repair of the generators.

The Company is uncertain whether, and to what extent, any of the remaining costs and revenues will be recovered through the ratemaking process.

PGT-PG&E Pipeline Expansion Project: The Company is constructing an expansion of its natural gas transmission system from the Canadian border into California. The 840

miles long pipeline will provide an additional 148 MMcf/d of firm capacity to the Pacific Northwest and an additional 755 MMcf/d of firm capacity to California. At December 31, 1992 and 1991, the Company's total investment in the project (which is included in construction work in progress) was approximately $979 million and $116 million, respectively. The $979 million at December 31, 1992 consisted of $457 million for the facilities within California (i.e., intrastate portion) and $522 million for the facilities outside California (i.e., interstate portion). Construction commenced in December 1991 and is scheduled to be completed in late 1993 at an escalated aggregate cost of approximately $1.7 billion.

The construction of facilities within the state of California has been certificated by the CPUC. The conditions of the certificate place the Company at risk for its decision to construct based on its assessment of market demand and for any potential underutilization of the facility. The certificate requires the application of a "cross-over" ban under which volumes delivered from the incremental interstate (PGT) expansion must be transported at an incremental intrastate rate. Incremental rate design is based on the concept that expansion shippers, not existing ratepayers, bear the incremental costs of the expansion project. Capacity on the interstate portion is fully subscribed under long-term firm transportation contracts. Due to regulatory and market uncertainty within California, shippers have only executed long-term firm transportation contracts for approximately one-half of the intrastate capacity and the Company continues negotiations for the remaining capacity. The CPUC also authorized the Company to provide interruptible service on the expansion project, which would provide additional revenues to recover the incremental costs of the expansion.

The CPUC certificate established a cost cap of $736 million for the California portion, which was based on cost estimates prepared in 1989 and represents the maximum amount determined by the CPUC to be reasonable and prudent. In December 1992, the Company requested an increase in the cost cap based on a revised California project cost of $849 million. Ultimate recovery of costs is subject to a CPUC reasonableness review. The Company plans to file its first Pipeline Expansion rate case in the first quarter of 1993 and will request interim rates to be effective on the commercial operation date of the project.

FERC has certificated construction of the interstate facilities but has indicated that certain intrastate elements, including the "cross-over" ban, may have established a discriminatory restraint on access into California affecting the interstate portion of the project. As a result of its concern, FERC reduced PGT's approved rate of return on equity on this project from the previously authorized 12.50% to 10.13% until such time that PGT demonstrates that neither its rates nor its transportation policies nor those of the Company result in unduly discriminatory restraints. The CPUC has reaffirmed its rate order establishing incremental pricing and the "cross-over" ban, resulting in petitions to FERC requesting revocation of the authorization to operate the interstate facilities when completed. PGT has filed for rehearing of the reduction in its rate of return and has opposed any imposition of an operational ban.

The Company believes that the ultimate outcome of the recovery of costs for the project would not have a significant impact on its financial position or results of operations.

Nuclear Insurance: The Company is a member of Nuclear Mutual Limited (NML) and Nuclear Electric Insurance Limited (NEIL I and II). If the nuclear plant of a member utility is damaged or increased costs for business interruption are incurred due to a prolonged accidental outage, the Company may be subject to maximum assessments of $21 million (property damage) or $8 million (business interruption), in each case per policy period, if losses exceed premiums, reserves and other resources of NML, NEIL I or NEIL II.

The federal government has enacted laws that require all utilities with nuclear generating facilities to share in payment for claims resulting from a nuclear incident. The Price-Anderson Act limits industry liability for third-party claims resulting from any nuclear incident to $7.5 billion per incident. Coverage of the first $200 million is provided by private insurance. If a nuclear incident results in public liability claims in excess of $200 million, the Company may be assessed up to $126 million per incident, with payments in each year limited to a maximum of $20 million per incident. If additional funds are needed to satisfy public liability claims and legal costs arising from any nuclear incident, the Company can be assessed an additional $6.3 million per incident.

Geothermal Steam Contracts Litigation: In late 1986 and early 1987, two lawsuits were filed against the Company relating to contracts for sale of geothermal steam to the Company for use at the Geysers Power Plant (Geysers). In total, the lawsuits claimed damages in excess of $120 million for breaches of contract. Union Oil Company of California (Unocal) has a 75% interest in the lawsuits and Thermal Power Company (Thermal) has the remaining 25% interest. The Company had filed a cross-complaint requesting damages in excess of $57 million. In 1991, Unocal and the Company signed settlement agreements and new steam sale agreements to settle the litigation between them. The agreements become effective upon receipt of certain regulatory approvals. Under the settlement, Unocal would pay the Company $43 million for costs the Company incurred for a plant that was never built because of insufficient steam, and the Company would pay Unocal $13 million in settlement of Unocal's claim that the steam price was improperly calculated. In addition, Unocal would receive the equipment purchased for that particular Geysers unit or, if the Company sells the equipment before the new agreement becomes effective, the net proceeds of the sale. Upon

receipt of the regulatory approvals, all other claims of both parties would be dismissed.

In July 1992, the Company also signed a settlement agreement and a new steam sale agreement with Thermal. The agreements become effective upon receipt of certain regulatory approvals. Under the settlement, the Company paid Thermal $5 million in settlement of Thermal's claim that the steam price was improperly calculated. Upon receipt of the regulatory approvals, all other claims of both parties would be dismissed. If regulatory approvals are not received, then Thermal would be required to refund the $5 million to the Company.

In July 1992, the Company applied to the CPUC for approval of the settlement agreements and new steam sale agreements and for rate recovery of the various payments required under these agreements, including the $13 million and $5 million settlement payments to Unocal and Thermal, respectively. The Company believes that the ultimate outcome of this matter will not have a significant impact on its financial position or results of operations.

Environmental Cleanup: The Company assesses, on an ongoing basis, measures that may need to be taken to comply with laws and regulations related to environmental cleanup activities, primarily at retired manufactured gas plant sites. Although the overall costs of these measures are difficult to estimate due to uncertainty about the extent of environmental risks and the Company's responsibility, the complexity of environmental laws and regulations, and the selection of alternative compliance approaches, the Company has a liability at December 31, 1992 of $67 million for its estimate, at that date, of overall cleanup costs.

To the extent that environmental cleanup costs are not recovered through insurance or by other means, the Company will apply for recovery through ratemaking procedures established by the CPUC and expects that most prudently incurred environmental remediation costs will be recovered through rates. The Company has recorded a deferred charge for approximately 90% of environmental cleanup costs, which represents the minimum amount of such costs expected to be recovered under the current ratemaking mechanism. Due to expected regulatory treatment, the Company believes that the ultimate outcome of these matters will not have a significant impact on its financial position or results of operations.

OTHER INFORMATION

Quarterly Consolidated Financial Data (Unaudited)

Quarterly financial data for the four quarters of 1992 and 1991 are shown below. Due to the seasonal nature of the utility business and the scheduled refueling outages for Diablo Canyon, operating revenues, operating income, and net income are not generated evenly by quarter during the year. Earnings for the second quarter of 1992 included a $19 million after-tax gain from the sale by PGT of its 49.98% interest in ANG. In the first quarter of 1991, ANG wrote off its investment in a magnesium metal production facility project in Alberta, Canada; as a result, the Company's earnings decreased approximately $26 million after tax.

The Company's common stock is traded on the New York, Pacific, London, Amsterdam, Basel and Zürich stock exchanges. There were approximately 254,000 common shareholders of record at December 31, 1992. Dividends are paid on a quarterly basis, and there are no significant restrictions on the present ability of the Company to pay dividends.

	Quarter ended			
(in thousands, except per share amounts)	December 31	September 30	June 30	March 31
1992				
Operating revenues	$2,557,787	$2,798,763	$2,519,679	$2,419,859
Operating income	386,196	507,137	491,131	448,977
Net income	205,804	351,939	336,409	276,429
Earnings per common share (1)	.44	.78	.75	.61
Dividends declared per common share	.44	.44	.44	.44
Common stock price per share				
High	34.00	34.63	33.63	32.38
Low	30.00	31.13	29.00	29.13
1991				
Operating revenues	$2,635,012	$2,520,341	$2,351,887	$2,270,879
Operating income	405,592	494,483	474,487	338,517
Net income	246,889	334,597	305,543	139,363
Earnings per common share (1)	.54	.75	.67	.28
Dividends declared per common share	.41	.41	.41	.41
Common stock price per share				
High	32.63	29.25	27.38	26.25
Low	28.63	24.63	24.75	24.00

(1) Includes Diablo Canyon scheduled refueling outages for the fourth and third quarters of 1992 and for all quarters of 1991.

Notification Regarding Form 10-K and Summary Annual Report

Copies of the Company's 1992 Form 10-K or the Summary Annual Report (which includes the Letter to Shareholders, a discussion of operations and other information) can be obtained by writing to the Company's Transfer Agent, Daniel T. Lamey, Shareholder Services, 77 Beale Street, Mail Code B26B, P.O. Box 770000, San Francisco, CA 94177 or by calling 1-800-367-7731.

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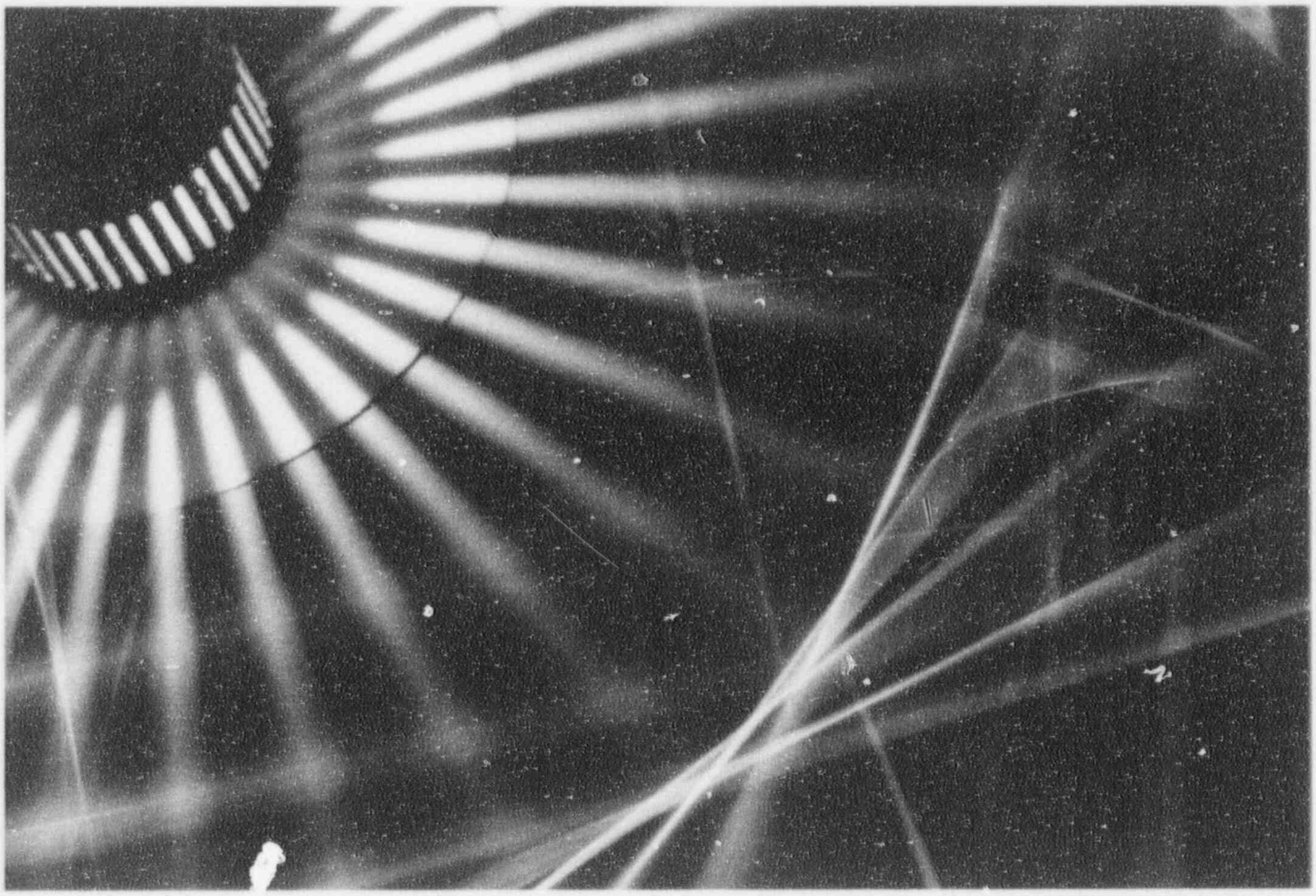


1992 SUMMARY ANNUAL REPORT

PG&E

PG&E is the nation's largest investor-owned gas and electric utility, serving more than 12 million people in Northern and Central California. Our electricity comes from widely diversified resources – fossil-fuel plants, hydroelectric plants, a major pumped storage plant, a geothermal complex, the Diablo Canyon Nuclear Power Plant and from such renewable technologies as wind power, solar power and biomass. Our natural gas comes from Canada, the U.S. Southwest and California.

CONTENTS

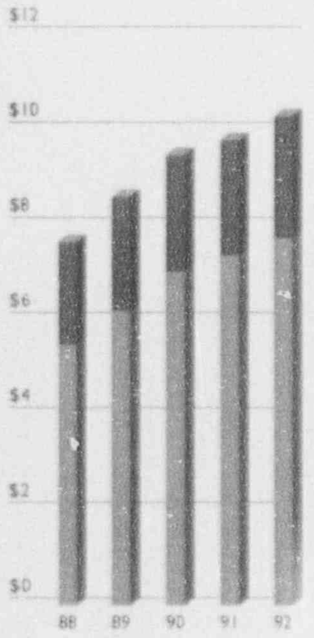
The company's 94,000-square-mile service territory stretches from Eureka in the north to Bakersfield in the south and from the Pacific Ocean in the west to the Sierra Nevada in the east.

Cover: A [illegible] model at PG&E's Pacific Energy Center shows customers and builders how to get the most light from high-efficiency [illegible]. Energy efficiency is at the heart of PG&E's business strategy.

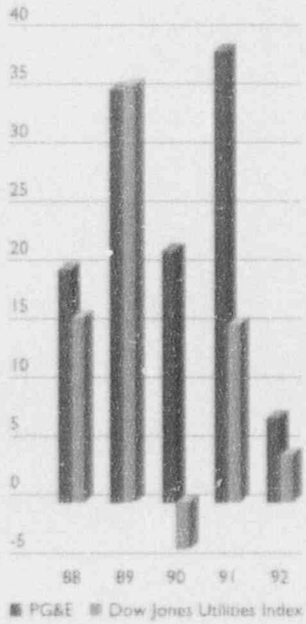
HIGHLIGHTS

(dollars in millions, except per share amounts)	1992	1991	% change
FOR THE YEAR			
Operating revenues	$10,296	$ 9,778	5
Operating income	$ 1,833	$ 1,713	7
Net income	$ 1,171	$ 1,026	14
Earnings available for common stock	$ 1,092	$ 937	17
Earnings per common share	$ 2.58	$ 2.24	15
Dividends declared per common share	$ 1.76	$ 1.64	7
Construction expenditures (including AFUDC)	$ 2,391	$ 1,796	33
Total electric sales to customers (kWh – in millions)	75,285	74,196	1
Total gas sales to customers (Mcf – in millions)	429	428	–
AT YEAR END			
Total assets	$24,188	$22,901	6
Total customers	7,835,000	7,757,000	1
Number of common shareholders	254,000	261,000	(3)
Number of common shares outstanding	426,845,569	417,571,826	2
Number of employees (excluding subsidiaries)	26,600	26,700	–

Consolidated Operating Revenues
(in billions)



Total Return on Common Stock Investment[1]
(in percent)



[1]Total return is a combination of dividends and change in stock price.

performed the Dow Jones Utilities Index again in 1992, closing the year at $33¾.

Over the last five years, PG&E has provided shareholders an average total return of 24 percent annually – compared to 12.4 percent for the Dow Jones Utilities Index.

Based on the company's solid performance in 1992, and confidence that we can build on that performance, the Board of Directors on January 20, 1993, raised the quarterly dividend on common stock to 47 cents per share.

This marked the fourth time in four years the company has raised the dividend, and brought the new annualized rate to $1.88 per share.

Stanley T. Skinner, President and Chief Operating Officer, and Richard A. Clarke, Chairman of the Board and Chief Executive Officer.

What's ahead

The company will continue to reposition itself in the gas business, where its role has been redefined. As many major customers are purchasing more of their own gas supplies, PG&E is becoming more of an intrastate transporter rather than a marketer of gas.

Our markets for this service have expanded to include some major Southern California customers.

Because of the changes in our gas business, the company will no longer purchase as much gas and will sell its interests in pipelines and other natural gas facilities outside California.

Accordingly, in June, Pacific Gas Transmission Company, a wholly owned subsidiary of PG&E, sold its 49.98 percent interest in Alberta Natural Gas Company Ltd to TransCanada PipeLines Limited of Calgary, Alberta, for an after-tax gain of $19 million.

Changes to our electric business are also on the way. These changes unquestionably will lead to alternatives to the traditional role of the regulated electric utility.

PG&E anticipated this fundamental shift in the nature of our business and is effectively positioned to take advantage of the opportunities it affords.

The outlook for future earnings growth is positive. Our utility business is strong, and we serve a market that is economically diverse and powerful. Diablo Canyon continues to provide the opportunity to achieve superior earnings growth.

The scheduled completion of the PGT-PG&E Pipeline Expansion Project at the end of this year, as well as continued progress in PG&E's unregulated businesses, are expected to further improve our future earnings.

For all of these reasons, we strongly believe PG&E's prospects are promising and we can continue to provide excellent value to our shareholders, our customers and the communities we serve.

Richard A. Clarke

Richard A. Clarke
Chairman of the Board and
Chief Executive Officer

Stanley T. Skinner

Stanley T. Skinner
President and
Chief Operating Officer

February 1, 1993

In developing its business strategy over the past six years, PG&E foresaw many of the directions established by the Energy Policy Act of 1992. This positions the company to maintain its industry leadership through the rest of the decade and beyond. Here are some examples.

A more competitive power supply market

The Energy Policy Act amends the Public Utility Holding Company Act (PUHCA) to encourage competition in electric generation. The Clinton administration appears to support this change.

Several years ago, regulators in many states established rules requiring new power plants to be built through bidding processes that often placed the local utility at a disadvantage. As a result, if a utility wanted to remain in the business of building and owning power plants, it had its best opportunity to do so outside its service territory. This created new markets for power plant construction nationwide, an opportunity PG&E seized upon.

In just three years, PG&E has become the fourth largest net equity participant in this market through U.S. Generating Company, an unregulated affiliate that is in partnership with Bechtel Group, Inc.

U.S. Generating Company builds, owns and manages independent power projects nationwide. These plants use advanced natural gas and clean-coal combustion technologies and emission controls.

Currently, U.S. Generating Company owns interests in two plants in operation, one in Colstrip, Montana, and the other in Panther Creek, Pennsylvania. In addition, it is building seven plants in Florida, New York, New Jersey, Massachusetts and Pennsylvania. Five more projects are in advanced stages of development. Together, these plants will have an installed capacity of nearly 2,500 megawatts.

The amendment of PUHCA enables utility subsidiaries, such as PG&E's U.S. Generating Company, to compete more effectively with non-utilities in this growing market.

Energy efficiency

The act encourages state regulators to make achieving energy efficiency at least as profitable for utilities as investment in generation, transmission and distribution. The new administration appears to support these provisions, and envisions the U.S. becoming as energy efficient as western Europe and Japan.

PG&E is the world's largest private investor in energy-efficiency programs. They have saved our customers an estimated $3 billion to $4 billion over the past 17 years.

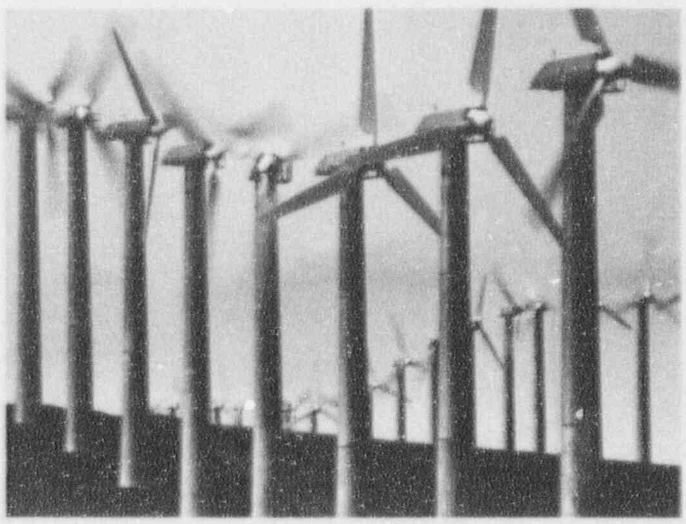
Under an innovative agreement among California utilities, regulators and environmentalists, PG&E's shareholders earn on the energy savings achieved by our customers as a result of our programs.

This ambitious effort is at the heart of our electric resource plan: to meet 75 percent of the growth in our area's electric needs between now and the year 2000 through increased customer energy efficiency (CEE). This represents several large generating units PG&E or other suppliers won't have to build, and by 2000 will avoid three million tons of carbon dioxide being emitted into the air annually. This is the equivalent of taking 600,000 cars off California roads.

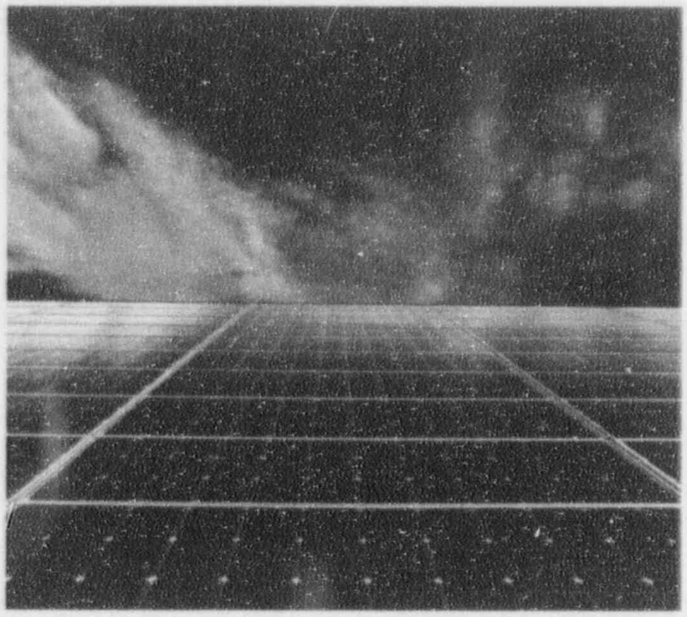
Energy efficiency can benefit the economy as well as the environment. CEE programs cost less than the amount required to build a major new power plant. Our programs are saving money for businesses and individual customers; creating new jobs in developing and installing energy-efficient technologies; and making the farms and factories we serve operate more efficiently and competitively.

Renewables

Renewable technologies are encouraged under the energy act through public/private joint ventures and favorable tax treatment of alternatives such as wind, solar and biomass. The Clinton administration would establish a civilian research agency to develop renewable technologies.



Renewable resources such as wind are an important source of electricity.



Solar panels convert sunlight directly into electricity.

PG&E has, for many years, produced electricity from a wide range of renewable energy sources. We operate the world's largest privately owned hydro and geothermal systems and are one of the major purchasers of wind power.

Today our research and development efforts continue to explore and test technologies that lead to a cleaner environment. As a result of a collaborative R&D effort of PG&E and others, the next generation of wind turbines, using variable speed technology to increase output, is about ready for commercial development.

As the utility industry moves toward smaller, more widely distributed electric generation, PG&E is researching technologies that will be cost effective and environmentally preferred. In 1992, the company, in collaboration with others, installed a 500-kilowatt solar energy system near Fresno. As the unit begins operation this year, researchers will monitor and evaluate its performance and its ability to support our existing electric system.

Clean-air vehicles

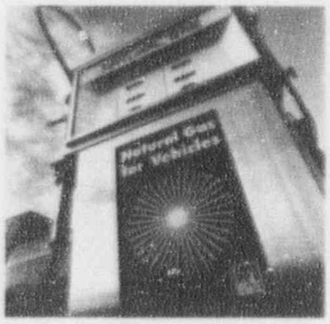
Federal, state and private fleet operators will be required to phase in vehicles operating on clean-burning alternative fuels under the energy bill. The new administration has indicated interest in converting the entire federal vehicle fleet to operate on natural gas.

PG&E began experimenting with natural gas vehicles almost 20 years ago. Today, we have the fastest growing, utility-operated natural gas vehicle program in the nation.

In California, where millions of vehicles burning gasoline and diesel are the major source of air pollution, natural gas is an attractive alternative fuel. It is cleaner burning and more economic than gasoline or diesel, and unlike the petroleum from which gasoline is produced, natural gas is abundant in the U.S. and Canada.

PG&E's goal by the end of the decade is for 125,000 fleet vehicles to operate on natural gas in Northern and Central California.

In addition, we are committed to ensuring sufficient fueling stations to facilitate their use and are working to develop a network of such facilities in our service area.



Natural gas fueling stations serve fleet vehicles in California.

Using natural gas in fleet buses, vans and trucks makes sense today, and electric vehicles, which produce no tailpipe emissions, are likely to become a major transportation option tomorrow. PG&E continues to actively support their development.

In the future, we believe clean fuels – particularly natural gas which is the most environmentally acceptable of the fossil fuels – will play a greater energy role in our nation.

In the last 15 years, PG&E has been using more natural gas in lieu of oil to generate electricity. Other utilities in the state are anxious to do the same as stricter air quality regulations come into effect. The PGT-PG&E pipeline expansion from Canada will provide them with greater access to this clean fuel.

Looking further ahead, the demand for this environmentally superior fuel in a wide variety of industrial applications should grow. This should increase the business opportunities for PG&E Resources, our unregulated affiliate that explores for and produces natural gas and oil reserves for sale on an unregulated basis nationwide.

THE SUN'S RAYS ARE AN IMPORTANT AND PREDICTABLE CLIMATIC FACTOR IN ARCHITECTURAL DESIGN. THE PACIFIC ENERGY CENTER HAS A NUMBER OF SYSTEMS AVAILABLE TO SIMULATE THE DAILY AND SEASONAL EFFECTS OF SUN PATTERNS AND SHADING DEVICES.

Customer energy efficiency

PG&E's Customer Energy Efficiency (CEE) programs are a model for the nation, providing Californians both lower energy bills and cleaner air.

Approximately 600,000 of PG&E's customers participated in some 50 CEE programs in 1992, saving enough electricity to supply almost 91,000 homes for a year, and enough gas to heat about 86,000 homes annually. As a result, air emissions were reduced by more than 3.8 million tons of carbon dioxide.

Shareholders will earn in excess of $50 million pretax under an agreement with regulators that allows the company to earn based on the energy savings achieved. As a result of new accounting guidelines, however, most of these earnings were not booked in 1992. Rather, they will accrue to shareholders in 1993 and 1994.

CEE programs demand no sacrifice in comfort or convenience; they are achieved through more efficient technologies in lighting, heating and cooling, manufacturing, and construction techniques for all customers: residential, commercial, agricultural and industrial.

Many of these new products and systems earn rebates from PG&E. All of them save energy and money. Energy-efficient techniques are available to every PG&E customer, from a mobile home park resident installing weatherstripping to a huge manufacturing plant overhauling all its lighting, heating and ventilation systems.

For example, a large oil refinery in PG&E's Diablo Division installed new heat exchangers that will result in a savings of three million therms and reduce their costs of operation by more than $1 million a year. The refinery received a PG&E rebate of $94,900 for the retrofit in addition to the energy rebates it earned in 1991 of more than $200,000.

Energy savings on a broader scale can be realized simply by changing the light bulbs customers use. New fluorescent bulbs use 75 percent less energy than traditional bulbs. In December PG&E joined three lighting manufacturers to offer rebates to partially offset the cost of new compact fluorescent bulbs.

The result of another PG&E collaboration – a technologically advanced energy-efficient home – was dedicated in Rocklin in 1992. This combination house and laboratory, featuring nearly every energy saving device available, is a joint project of PG&E, the Building Industry Association of Superior California, and the California Energy Commission.

Much of this advanced technology is on display at the Pacific Energy Center in San Francisco, where some 6,500 customers saw demonstrations, attended classes or used the reference library in the first year of operation.

Many of these customers were victims of the 1991 Oakland hills fire, who were interested in incorporating energy efficiency into the homes they are rebuilding.

Architects, lighting designers, engineers and building professionals also used this facility, one of the most advanced in the nation. These experts experimented with full-scale displays of advanced lighting, heating and air-conditioning techniques.

PG&E is not only showcasing the new products; it is helping provide the incentive to make even greater advances. Along with some 24 other utilities, the company contributed to a $30 million award to the manufacturer that develops a refrigerator at least 25 to 50 percent more energy efficient than federal government standards. The refrigerator must also be free of chlorofluorocarbons (CFCs) which deplete the ozone. Frigidaire and Whirlpool are finalists in the competition to produce this super model.

According to the Environmental Protection Agency, such a refrigerator will reduce CFC emissions by as much as 1.2 million tons by 2000 and lower customer energy bills by up to $480 million a year.

ONE OF CALIFORNIA'S MAJOR ELECTRIC RESOURCES, THE DIABLO CANYON NUCLEAR POWER PLANT, HAS ESTABLISHED AN EXCELLENT SAFETY AND OPERATING RECORD AND PRODUCES SIGNIFICANT REVENUES.

Environment

Combining energy services with a commitment to improve the environment produces major results: millions of therms, kilowatthours and dollars saved; millions of tons of pollutants kept out of the air. But there is more to PG&E's promise to the environment – programs and people who produce smaller, less quantifiable, but equally valuable victories.

PG&E owns and manages more than 250,000 acres of forest and lakes in California, home to some 150 rare, threatened or endangered species of wildlife. We are committed to being sound environmental stewards of these lands. We made solid achievements in this area in 1992.

PG&E continued to participate in the recovery of the endangered peregrine falcon in California.

PG&E acted to preserve the biodiversity of thousands of acres of coastline and inland property near the Diablo Canyon plant. A similar effort to protect tidal wetlands and restore native plants and animals is being conducted on Suisun Bay at our Pittsburg Power Plant.

The company began to acquire some 1,400 acres of land in the San Joaquin and Sacramento valleys to be ceded to the state as habitat for the threatened San Joaquin kit fox. The company fenced the property and established an endowment which the state will use to protect the land.

Environmental considerations have become a key part of planning and operating decisions – from the environmental impact analysis required on new capital project proposals to the "green" catalogues used to order environmentally preferred materials.

In 1992, PG&E employees recycled paper, aluminum cans, glass bottles, motor oil, batteries, tires, plastic gas pipe and more than 1,000 truckloads of soil used for backfill.

Company volunteers planted seedlings in the Mendocino and Stanislaus National Forests that were devastated by fire in 1987. Others put in some 4,0[illegible] plants and flowers at Antioch Dunes, the nation's first refuge for endangered plants and insects.

Diablo Canyon

The Diablo Canyon Nuclear Power Plant continues to gain national recognition for its safe and reliable operations.

The Nuclear Regulatory Commission (NRC) placed Diablo Canyon on its "Best Plants" list in February and July of '92 and again in February '93. The rating was based on the NRC's evaluation of Diablo Canyon's performance, including operational safety, self-assessment, problem resolution, and plant management and oversight.

In November Unit 1 completed its scheduled refueling outage in 59 days, a record for the unit. The plant operated at a combined capacity factor of 88 percent, compared to a budgeted 79.7 percent. It produced about 17 billion kilowatthours of electricity and contributed $1.78 billion to PG&E's revenues.

In 1992, PG&E requested that the NRC amend the plant's 40-year license to take effect on the date of operation instead of the construction permit date.

If the amended licenses are approved, the expiration dates for Units 1 and 2 will be 2021 and 2025, respectively, extended from 2008 and 2010.

Competition

There is a growing interest in alternatives to traditional utility service today. To compete effectively, PG&E must control costs, know which services customers value, and deliver those services at a competitive price.

We are taking aggressive steps to control costs. Our operating expense budgets for 1993 will remain nearly flat, as they have for the past seven years.

Taking advantage of low interest rates, we refinanced $1.4 billion worth of bonds and preferred stock in 1992. The value of the savings over the life of the redeemed securities pretax is $155 million.

SYSTEM OPERATORS IN THE ENERGY CONTROL CENTER BALANCE A COMPLEX SERIES OF FACTORS – GENERATION AND POWER PURCHASE COSTS, FACILITY AVAILABILITY AND THE EFFECT OF LINE LOSSES – AS THEY MAXIMIZE PG&E'S RELIABILITY AND OPERATING ECONOMY.

We also have begun a comprehensive program to reduce the amount of new capital required to build and maintain facilities to distribute gas and electricity to our customers.

Our immediate goal is to cut the cost of connecting new customers to our system by 25 percent.

To accomplish this, we are seeking greater economies and efficiencies in a wide range of activities – everything from how we construct trenches for gas facilities to ways to use existing transformers more efficiently. All these efforts are expected to achieve total annual savings in excess of $150 million by 1996.

To gain greater organizational efficiency, we will be restructuring our business units. These changes are designed to enable PG&E to provide maximum value to our customers: service that is even more responsive to their needs at prices that are competitive.

Delivering that value requires a streamlined organization with fewer layers of management and greater participation in decision-making by employees closest to the work on how the work can best be done.

In addition, we are taking steps to capture more fully the efficiencies afforded by new technologies and developing an employee team that can work across organizational lines.

Cost management and effective organization are essential to satisfying customers. But knowing exactly which services our customers value is just as important.

Through a very precise research and planning process called "Voice of the Customer," PG&E is determining the level of overall satisfaction with our service. Using this data, PG&E will work to increase the company's level of performance on each element of service our customers deem important.

Education and the workplace

In a rapidly changing, highly competitive business climate, employees need new skills to keep pace with technological advances. PG&E needs employees to participate in making decisions on how to get the job done better – decisions based on a solid understanding of company goals, mission and business strategy.

That's why education is vital to PG&E and every member of our employee team. Central to our educational effort is the Blueprint for Learning – a comprehensive plan for continuous learning and management of training resources through the end of the decade.

New PG&E workers learn the company's basic business, its mission and goals, and the role they will have in building shareholder value and improving the services we offer.

Employees currently on the job are offered a wide range of courses that will help them acquire the skills necessary to advance their careers.

Last year, the company invested $125 million in education and devoted two million hours to training the men and women it employs. On any given work day, 1,100 PG&E people were attending class.

With the dedication in 1992 of the new Construction Training Center at Livermore and the completion this year of the expansion of our San Ramon Learning Center, PG&E will have one of the nation's most advanced utility education complexes.

The growing numbers of working parents on the job at PG&E welcomed the dedication of another new facility in 1992: the PG&E Children's Center. The 77 Beale headquarters now houses the first day-care center of its kind in the San Francisco financial district.

This professionally operated resource for parents of infants, toddlers and pre-schoolers was cited by *Working Mother* magazine, which named PG&E one of the country's best companies for working women.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Shareholders and the Board of Directors of Pacific Gas and Electric Company:

We have audited the consolidated balance sheet and the statement of consolidated capitalization of Pacific Gas and Electric Company and subsidiaries as of December 31, 1992 and 1991, and the related statements of consolidated income, cash flows, common stock equity and preferred stock, and the schedule of consolidated segment information for each of the three years in the period ended December 31, 1992, included in the proxy statement for the 1993 annual meeting of shareholders of the Company (not presented herein). Our report dated February 1, 1993, also appearing in that proxy statement, contained explanatory paragraphs that describe the uncertainties regarding the ultimate outcome of certain natural gas matters, as discussed in Note 2 of Notes to Consolidated Financial Statements, and recovery of Helms costs and revenues, as discussed in Note 10 of Notes to Consolidated Financial Statements.

In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 1992 and 1991, and in the related condensed statements of consolidated income and cash flows for each of the three years in the period ended December 31, 1992, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

ARTHUR ANDERSEN & CO.
San Francisco, California
February 1, 1993

RESPONSIBILITY FOR FINANCIAL STATEMENTS

The condensed consolidated financial statements in this summary annual report were derived from the consolidated financial statements that appear in the proxy statement for the 1993 annual meeting of shareholders. Management is responsible for preparing the consolidated financial statements, in accordance with generally accepted accounting principles appropriate in the circumstances, and for maintaining and monitoring the Company's systems of internal accounting controls. A description of these controls, along with management's opinion about their overall effectiveness, is contained within Responsibility for Financial Statements included in the proxy statement. The consolidated financial statements were audited by Arthur Andersen & Co., the Company's independent public accountants, whose report on the condensed consolidated financial statements appears above.

The financial statements on the following page have been condensed. More detailed financial information is provided in the proxy statement.

CONDENSED STATEMENT OF CONSOLIDATED INCOME

Year ended December 31 *(in millions, except per share amounts)*	1992	1991	1990
Operating revenues	$10,296	$9,778	$9,470
Operating expenses	8,463	8,065	7,764
Operating income	1,833	1,713	1,706
Other income – net	124	94	85
Interest expense	786	781	804
NET INCOME	1,171	1,026	987
Preferred dividend requirement	79	89	98
EARNINGS AVAILABLE FOR COMMON STOCK	$ 1,092	$ 937	$ 889
EARNINGS PER COMMON SHARE	$ 2.58	$ 2.24	$ 2.10
DIVIDENDS DECLARED PER COMMON SHARE	$ 1.76	$ 1.64	$ 1.52

CONDENSED CONSOLIDATED BALANCE SHEET

December 31 *(in millions)*	1992	1991
Plant in service	$ 27,734	$26,432
Accumulated depreciation and decommissioning	(10,508)	(9,473)
Net plant in service	17,226	16,959
Construction work in progress	1,534	712
Other noncurrent assets	1,427	1,370
Current assets	3,018	2,913
Deferred charges	983	947
TOTAL ASSETS	$ 24,188	$22,901
Capitalization	$ 17,599	$16,917
Other noncurrent liabilities	587	534
Current liabilities	3,503	3,096
Deferred credits	2,499	2,354
TOTAL CAPITALIZATION AND LIABILITIES	$ 24,188	$22,901

CONDENSED STATEMENT OF CONSOLIDATED CASH FLOWS

Year ended December 31 *(in millions)*	1992	1991	1990
Net income	$ 1,171	$ 1,026	$ 987
Adjustments to net income (primarily depreciation and decommissioning)	1,389	1,699	1,385
Net cash provided by operating activities	2,560	2,725	2,372
Net cash used by investing activities	(2,320)	(2,245)	(1,663)
Net cash used by financing activities	(239)	(484)	(675)
NET CHANGE IN CASH AND CASH EQUIVALENTS	1	(4)	34
CASH AND CASH EQUIVALENTS AT JANUARY 1	97	101	67
CASH AND CASH EQUIVALENTS AT DECEMBER 31	$ 98	$ 97	$ 101

Board of Directors

Richard A. Clarke
Chairman of the Board and Chief Executive Officer, Pacific Gas and Electric Company

Harry M. Conger
Chairman of the Board and Chief Executive Officer, Homestake Mining Company

William S. Davila
President Emeritus, The Vons Companies, Inc. (retail grocery)

Ira Michael Heyman
Professor of Law, University of California, Berkeley

Melvin B. Lane
Publishing Consultant to Time Warner Inc. (publishing, music, and entertainment)

Leslie L. Luttgens
San Francisco Bay Area community leader

Richard B. Madden
Chairman of the Board and Chief Executive Officer, Potlatch Corporation (diversified forest products)

George A. Maneatis
Former President, Pacific Gas and Electric Company

Mary S. Metz
Dean of University Extension, University of California, Berkeley

*Frederick W. Mielke, Jr.**
Former Chairman of the Board and Chief Executive Officer, Pacific Gas and Electric Company

William F. Miller
Professor of Public and Private Management and Professor of Computer Science, Stanford University

John B. M. Place
Former Chairman of the Board and Chief Executive Officer, Crocker National Corporation and Crocker National Bank

Samuel T. Reeves
President and Co-Chairman of the Board, Dunavant Enterprises, Inc. (cotton merchandising)

Carl E. Reichardt
Chairman of the Board and Chief Executive Officer, Wells Fargo & Company and Wells Fargo Bank, N.A.

John C. Sawhill
President and Chief Executive Officer, The Nature Conservancy (international environmental organization)

Stanley T. Skinner
President and Chief Operating Officer, Pacific Gas and Electric Company

Barry Lawson Williams
President, Williams Pacific Ventures, Inc. (venture capital and real estate)

Permanent Committees of the Board of Directors

Executive Committee
Within limits, may exercise powers and perform duties of the Board.

Richard A. Clarke (Chairman)
Harry M. Conger
Leslie L. Luttgens
Richard B. Madden
John B. M. Place
Stanley T. Skinner

Audit Committee
Reviews financial statements and internal accounting and control procedures with independent public accountants.

Harry M. Conger (Chairman)
William S. Davila
Melvin B. Lane
Mary S. Metz
Samuel T. Reeves

Finance Committee
Recommends long-range financial policies and objectives, and actions required to achieve those objectives.

Richard A. Clarke (Chairman)
Richard B. Madden
William F. Miller
Carl E. Reichardt
Stanley T. Skinner
Barry Lawson Williams

Nominating and Compensation Committee
Recommends candidates for nomination as directors, recommends compensation and employee benefit policies and practices, and reviews planning for executive development and succession.

Leslie L. Luttgens (Chairman)
Ira Michael Heyman
William F. Miller
John B. M. Place
John C. Sawhill

Public Policy Committee
Reviews public policy issues which could significantly affect customers, shareholders, employees, or the communities served, and recommends plans and programs to address such issues.

Richard A. Clarke (Chairman)
Ira Michael Heyman
Melvin B. Lane
Mary S. Metz
John C. Sawhill

* *Will retire April 21, 1995.*

PG&E Officers[†]

*Richard A. Clarke[*]
Chairman of the Board and
Chief Executive Officer

*Stanley T. Skinner[*]
President and
Chief Operating Officer

*Jerry R. McLeod[*]
Executive Vice President

*James D. Shiffer[*]
Executive Vice President

*Donald A. Brand[*]
Senior Vice President
and General Manager,
Engineering and Construction
Business Unit

*Robert D. Glynn, Jr.[*]
Senior Vice President
and General Manager, Electric
Supply Business Unit

*Benjamin F. Montoya[*]
Senior Vice President
and General Manager,
Gas Supply Business Unit

*Virgil G. Rose[*]
Senior Vice President
and General Manager,
Distribution Business Unit

*Gregory M. Rueger[*]
Senior Vice President
and General Manager,
Nuclear Power Generation
Business Unit

Norman L. Bryan
Vice President
Clean Air Vehicles

George F. Clifton, Jr.
Vice President
East Bay Region

Philip G. Damask
Vice President
Engineering and
Construction: Transmission
and Distribution

John C. Danielsen
Vice President
Computer and
Telecommunications Services

Ronald G. Domer
Vice President
Engineering and
Construction: Generation

Richard A. Draeger
Vice President
General Services

Roger J. Flynn
Vice President
San Joaquin Valley Region

Warren H. Fujimoto
Vice President
Nuclear Technical Services

Daniel E. Gibson
Vice President
Gas Supply

Howard V. Golub
Vice President and
General Counsel

Leland M. Gustafson
Vice President
Golden Gate Region

Robert J. Haywood
Vice President
Power Planning and Contracts

Thomas W. High
Vice President and
Assistant to the Chairman of
the Board

Grant N. Horne
Vice President
Corporate Communications

Jack F. Jenkins-Stark
Vice President and Treasurer

Donald L. Kennady, Jr.
Vice President
Redwood Region

John C. Keyser
Vice President
Marketing and Customer
Services

John E. Koehn
Vice President
Community and
Governmental Relations

William R. Mazotti
Vice President
Gas and Electric Technical
Services

Peter C. Nelson
Vice President
Mission Trail Region

Jackalyne Pfannenstiel
Vice President
Corporate Planning

James H. Pope
Vice President
Sacramento Valley Region

James K. Randolph
Vice President
Power Generation

Gordon R. Smith
Vice President and
Chief Financial Officer

James B. Stoutamore
Vice President
Gas Transmission and Storage

John D. Townsend
Vice President
Diablo Canyon Operations
and Plant Manager

Barbara Coull Williams
Vice President
Human Resources

Kent M. Harvey
Corporate Secretary

Thomas C. Long
Controller

Brian L. McGrath
Assistant Corporate Secretary

Kathleen Rueger
Assistant Corporate Secretary

Julia B. York
Assistant Treasurer

Chief Executive Officers of principal PG&E subsidiaries

Mason Willrich
President and Chief
Executive Officer
PG&E Enterprises

Stephen P. Reynolds
President and Chief
Executive Officer
Pacific Gas Transmission
Company

Donald McMorland
Chairman of the Board,
President and Chief
Executive Officer
Alberta and Southern
Gas Co. Ltd.

Chief Executive Officers of principal PG&E Enterprises subsidiaries and related ventures

Joseph T. Williams
President and Chief
Executive Officer
PG&E Resources Company

Joseph P. Kearney
President and Chief
Executive Officer
U.S. Generating Company

Earl H. Franklin
President and Chief
Executive Officer
U.S. Operating Services
Company

Mason Willrich
President and Chief
Executive Officer
PG&E Properties, Inc.

† *As of February 1, 1993*

* *Member Management Committee*

Shareholder Services Office

77 Beale Street
Room 2600
San Francisco, CA 94177
1-800-367-7731

If you have questions about your account or need copies of the Company's publications, please write to the Transfer Agent at the address shown below.

If you have general questions about PG&E or information contained in the summary annual report, please write to the Office of the Corporate Secretary at the address shown below.

Security analysts, portfolio managers or other representatives of the investment community should write to the Director of Investor Relations at the address shown below.

Corporate Secretary

Kent M. Harvey
77 Beale Street
Mail Code B32
P.O. Box 770000
San Francisco, CA 94177
(415) 973-2880

Transfer Agent

Daniel T. Lamey
77 Beale Street
Mail Code B26B
P.O. Box 770000
San Francisco, CA 94177
1-800-367-7731

Director of Investor Relations

Laura L. Mountcastle
77 Beale Street
Mail Code B8C
P.O. Box 770000
San Francisco, CA 94177
(415) 973-3007

Stock held in brokerage accounts ("street name")

When you purchase your stock and it is held for you by your broker, it is listed with the Company in the broker's name, or "street name." PG&E does not know the identity of individual shareholders who hold their shares in this manner – we simply know that a broker holds a certain number of shares which may be for any number of customers.

If you hold your stock in street name, you receive all dividend payments, publications, and proxy materials through your broker. If you are receiving unwanted duplicate mailings, you should contact your broker to eliminate the duplications.

Dividend Reinvestment Plan

If you hold certificates in your own name, rather than through a broker, you may automatically reinvest dividends from common and preferred stock in new shares of PG&E common stock through the Company's Dividend Reinvestment Plan. You may obtain the Plan prospectus and enrollment form by contacting the Shareholder Services Office. If your certificates are held by a broker (in "street name"), you are not eligible to participate in the Dividend Reinvestment Plan.

Replacement of dividend checks

If you do not receive your dividend check within five business days after the payment date, or if a check is lost or destroyed, you should notify the Shareholder Services Office so that payment may be stopped on the check and a replacement issued.

Lost or stolen certificates

If your stock certificate has been lost, stolen, or in some way destroyed, you should notify the Shareholder Services Office in writing immediately.

Annual meeting of shareholders

Date: April 21, 1993
Time: 2:00 p.m.
Location:
Masonic Auditorium
1111 California Street
San Francisco, California

A notice of the meeting, proxy statement, 1992 financial information, and proxy form are being mailed with this summary annual report on or about March 4, 1993, to all shareholders of record.

10-K Report

If you would like a copy of the Company's 1992 Form 10-K Report to the Securities and Exchange Commission, please contact the Shareholder Services Office.

1993 dividend payment dates

Common Stock	Preferred Stock
January 15	February 15
April 15	May 15
July 15	August 15
October 15	November 15

Stock exchange listings

PG&E's common stock is traded on the New York, Pacific, London, Basel, Zürich and Amsterdam stock exchanges. The official New York Stock Exchange symbol is "PCG" but the Company's common stock usually is listed in the newspaper under "PacGE."

The Company has 18 issues of preferred stock, most of which are listed on the American Stock Exchange and the Pacific Stock Exchange.

Issue		Newspaper symbol
First Preferred, Cumulative, Par Value $25 Per Share Redeemable:		
9.30%		PGEpfV
9.00%		PGEpfL
8.20%		PGEpfP
8.16%		PGEpfK
8.00%		PGEpfO
7.84%		PGEpfM
7.44%		PGEpfQ
6.57%		Unlisted
5.00%		PGEpfD
5.69%	Series A	PGEpfE
4.80%		PGEpfG
4.50%		PGEpfH
4.36%		PGEpfI
Non-Redeemable:		
6.00%		PGEpfA
5.50%		PGEpfB
5.00%		PGEpfC
$100 First Preferred, Cumulative, Par Value $100 Per Share		
10.17%		Unlisted
9.00%		Unlisted

Pacific Gas and Electric Company
77 Beale Street
P. O. Box 770000
San Francisco, CA 94177