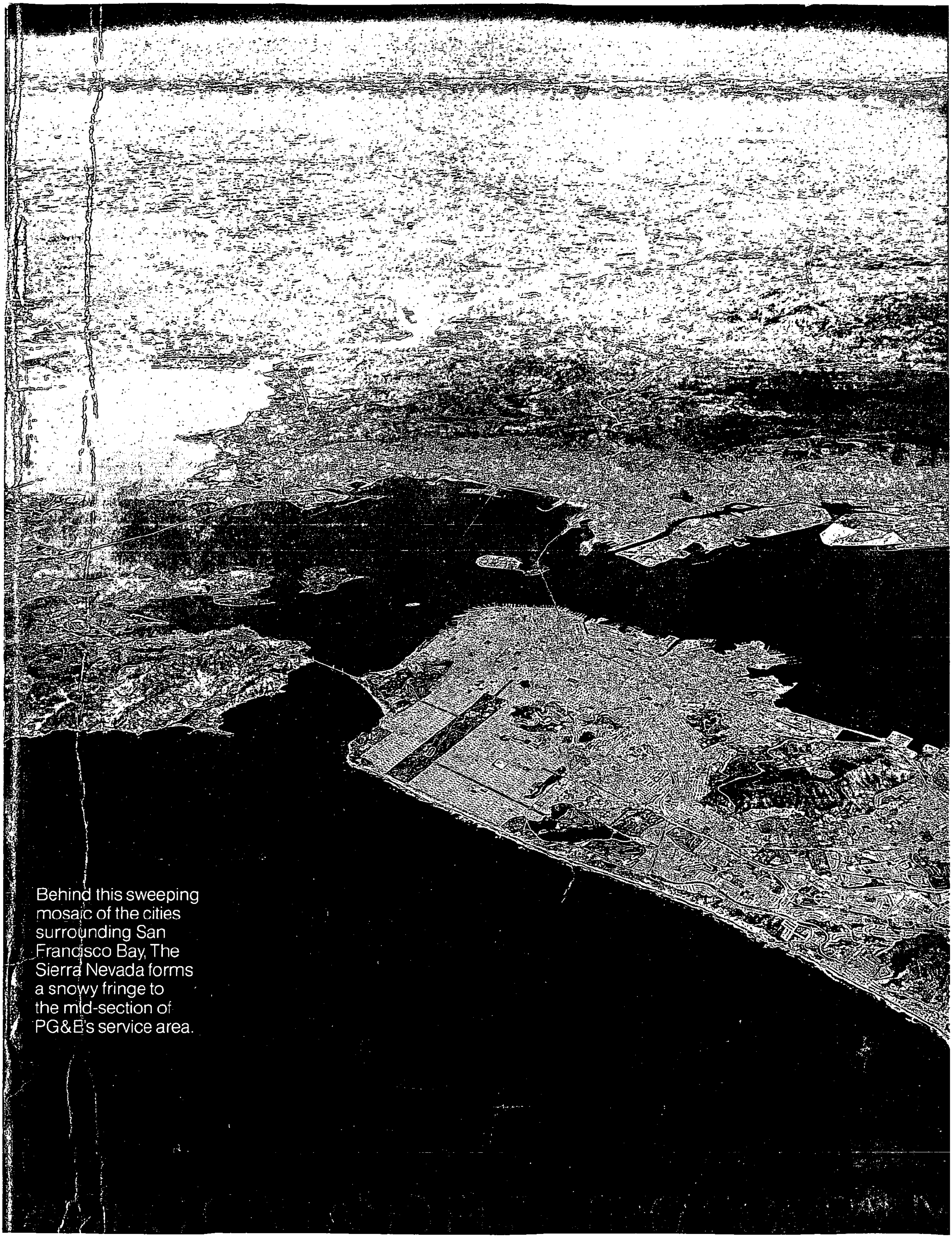
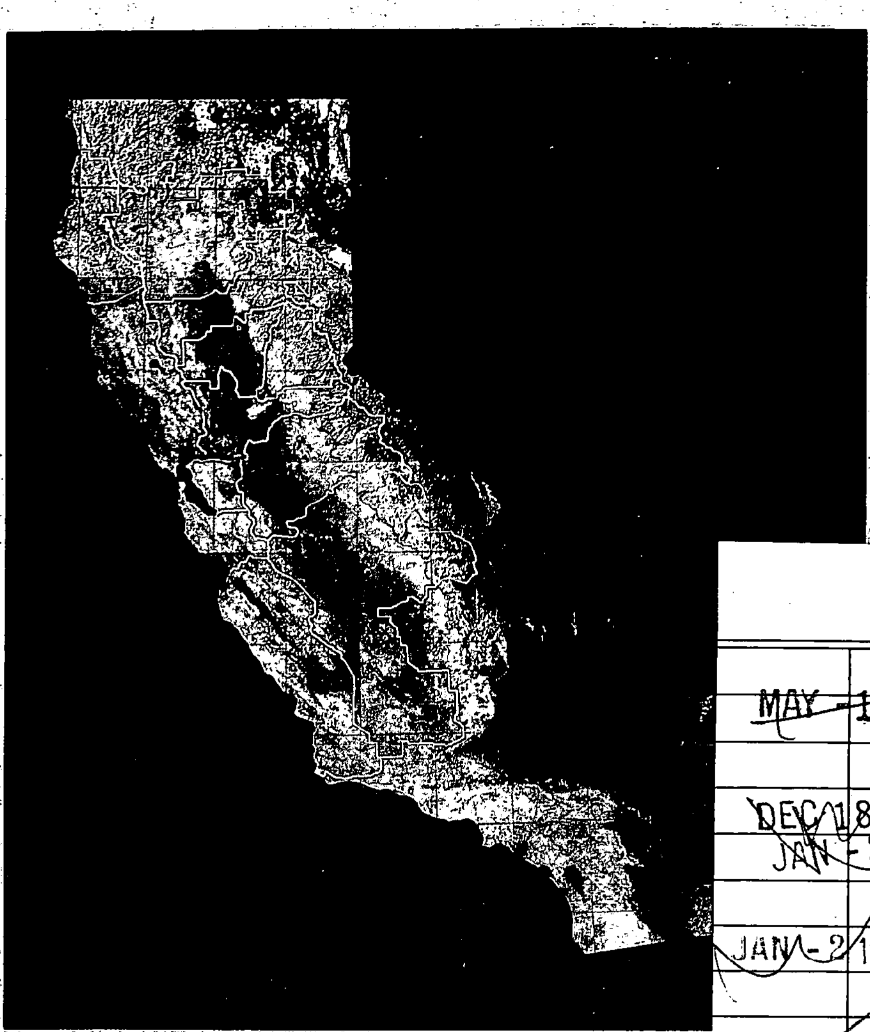


Behind this sweeping mosaic of the cities surrounding San Francisco Bay, The Sierra Nevada forms a snowy fringe to the mid-section of PG&E's service area.



It's a vital and ever-shifting challenge to bring natural gas and electricity to nine million people in some 1,300 Northern and Central California communities and rural areas.

How we address these challenges, while playing our vital service role across a huge and diverse land, is pictured in this annual report through the eyes of our 13 Division Managers.

Our Cover
Looking eastward over the Golden Gate Bridge that links Marin County (left) and San Francisco, over the East Bay and beyond the Central Valley to the Sierra Nevada 150 miles away—this infrared photograph is a panorama from a NASA U-2 aircraft 65,000 feet aloft.

Although making up less than one-third of PG&E country, the region within this photo is the home of some 3,700,000 Californians living in 22 counties and 65 incorporated cities.

MEETING THE CHALLENGES OF THE 1980's

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Contents

FINANCIAL HIGHLIGHTS

	1980	1979	Percent Change
Operating Revenues	**$ 5,258,899,000**	$ 4,364,469,000	20%
Net Income	**$ 524,770,000**	$ 458,234,000	15%
Earnings Available for Common	**$ 415,601,000**	$ 365,943,000	14%
Earnings Per Common Share	**$3.60**	$3.55	1%
Dividends Declared Per Common Share	**$2.60**	$2.38	9%
Total Assets	**$11,295,203,000**	$10,310,763,000	10%
Construction Expenditures	**$ 1,221,758,000**	$ 1,149,308,000	6%
Sales of Electricity to Customers (KWH)	**58,291,655,000**	59,728,452,000	-2%
Sales of Gas to Customers (MCF)	**558,892,000**	600,180,000	-7%
Total Customers	**6,316,244**	6,181,714	2%
Number of Stockholders	**402,985**	394,252	2%
Number of Employees	**27,582**	26,877	3%

TO OUR STOCKHOLDERS

The decade was ushered in by unprecedented inflationary forces which impacted every aspect of our business. Nevertheless, we were able to achieve a modest increase in our earnings per share of five cents to $3.60. This was possible only because of a general rate increase granted by the California Public Utilities Commission (CPUC) at the beginning of 1980.

The positive impact of this rate increase, however, was diminished, first, by a decline in electric sales due to a growing conservation ethic and reaction to higher energy costs on the part of our customers, and secondly, by the rapidly rising costs of labor, materials, and money.

For these reasons, PG&E's return on stockholders' common equity investment was only 11.7 percent—well below the 14.1 percent return determined to be fair and reasonable by the CPUC in its rate decision a year ago.

To counter the inflationary forces and to improve our financial position, the Company filed for, and recently received, an interim increase in its non-fuel-related rates for 1981. In addition, the Company applied for a general rate increase to become effective in January 1982, and hearings on this application are about to begin.

In the expectation that California regulation will be responsive to the Company's financial needs, and in recognition of the increased investment by our common stockholders through retained earnings, the Board of Directors recently increased the common stock dividend by three cents per share quarterly effective with the April 15, 1981 dividend payment. The new annual dividend rate becomes $2.72 per share.

Sales to Customers

Kilowatt hour sales of electricity in 1980 were down two percent from sales in 1979, but peak demand was up 1.7 percent. Volumes of gas sold were down seven percent.

These declines were due, in part, to short-term factors of lower economic growth, a warmer-than-normal cold season and cooler-than-normal warm season, and reduced agricultural pumping loads.

Over the longer range, we forecast continuing growth in demand through the 1980s averaging about two percent a year for electricity and 1.3 percent for natural gas.

Resource Plans

To meet this growth, the Company must make plans that will accommodate an even greater variety of environmental, regulatory, political, and financial considerations than in the past.

Energy has become the focal point of a number of ideological struggles. Arguments involve questions of renewable versus non-renewable energy resources, protection of scenic resources versus achievement of energy independence, low consumer prices versus decontrol of prices, greater environmental controls versus low-cost energy production, state policies versus federal policies—just to name a few.

Accordingly, we have taken a pragmatic approach in proposing plans to regulatory authorities for approval. We have proposed plans which strike the best balance we can between what we perceive to be society's desires, on the one hand, and the economic and engineering feasibility of providing energy supplies on the other.

Doing this, our current long-term resource planning calls for PG&E to continue to expend substantial sums to increase energy conservation, recognizing that saved energy is actually a source of energy that can be provided in many instances at less cost than can new supplies.

Looking ahead, after giving effect to energy conservation, we foresee a need to add 6,500,000 kilowatts of generating capacity to the PG&E area in the 1980s. We are planning to have 54 percent of these additions come from so-called "preferred" and renewable energy sources. Specifically, more than 1,500,000 kilowatts are planned to come from hydroelectric power. Another 1,100,000 kilowatts are planned to come from plants powered by geothermal steam. Cogeneration, along with plants fueled by solid waste and biomass, is being counted upon to contribute over 500,000 kilowatts, and we plan to have wind-powered generation furnish 82,000 kilowatts.

The remaining additions are planned to be 33 percent nuclear and 13 percent coal-fueled resources—specifically, 2,190,000 kilowatts from the Diablo Canyon Nuclear Power Plant, now awaiting licensing, and about 1,000,000 kilowatts from out-of-state coal-fueled plants. We are planning no new oil- or gas-fueled plants, except for cogeneration which involves the efficient joint use of other industrial heat processes which use these fuels.

For future gas supplies, our plans include the development of three new sources of supply, namely gas from the Alaskan North Slope, liquefied natural gas from South Alaska, and synthetic gas from coal. Additional supplies from the Rocky Mountain area also are planned.

Capital Requirements

Although our resource plans have been moderated because of lower growth forecasts, these plans still will require billions of dollars of new investment during the 1980s. Even conservation measures and the so-called "soft technologies" require large amounts of capital, particularly while they remain in the research and development stage.

The underpinning for this financing program is the issuance of additional shares of common stock equity. Unfortunately, so long as the market price of our stock remains below book value, as has been prevalent in our industry for many years, this financing requirement holds the prospect of future dilution of stockholders' interests as has occurred in the past.

The management of the Company is concerned about the short-run consequences of selling common stock below book value. However, we are also dedicated to maintaining the integrity of our shareholders' investment over the long-term. The achievement of this broader goal may necessitate the sale of common stock below book value.

California Regulation

Our ability to raise the large amounts of capital that will be required in the 1980s and our success in achieving a higher market value for our common stock will depend, in large measure, on the financial community's assessment of the outlook for the Company's financial condition in the ensuing years.

The key to this assessment, of course, will be the anticipated direction of California rate regulation.

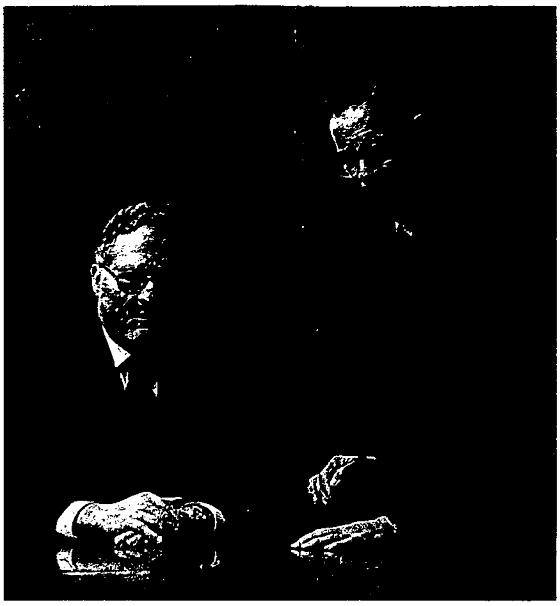
As stated earlier, we are optimistic that such regulation will be responsive to the financial needs of the Company. The timely granting in 1981 of our request for an interim rate increase and recent general rate decisions by the CPUC involving other utilities support our expectations.

Our pending request for a general rate increase in 1982 is designed to improve substantially the Company's cash flow and its overall financial integrity.

A realistic and responsive decision by the CPUC in this case will improve opportunities for our stockholders to earn an adequate return on their investment and permit the Company to maintain reliable service to its customers.

Organizational Changes

A number of new senior officers and vice presidents were elected effective April 1, 1981, and the Company's Management Committee was expanded. These new appointments, and some related changes in organizational structure described on page 19, will add significantly to the strength of the Company's management.



Barton W. Shackelford   Frederick W. Mielke, Jr.

Our Employees

It is always a pleasure to acknowledge the dedication and loyal performance of our employees.

As we contemplate the economic, technical, regulatory and political uncertainties of the 1980s, our optimism in meeting the challenges ahead reflects the high regard we hold for the men and women of PG&E.

Frederick W. Mielke, Jr.

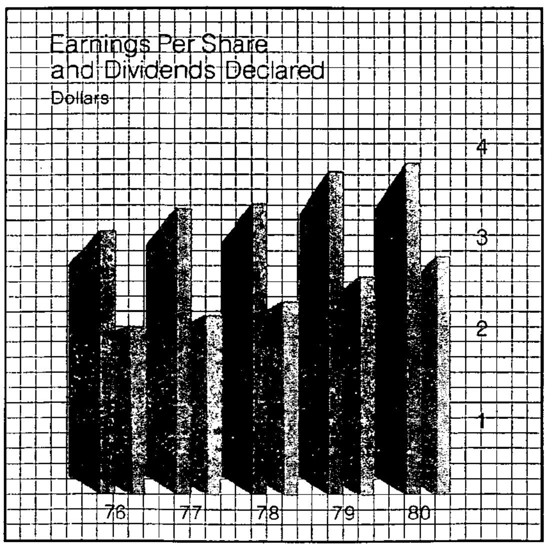
Frederick W. Mielke, Jr.
Chairman of the Board and
Chief Executive Officer

Barton W. Shackelford
President and
Chief Operating Officer

February 19, 1981

Operations Review

As PG&E moves to lessen its dependence on petroleum fuels, alternative energy resources are gaining greater importance. Successful conservation and load management programs are permitting the Company to defer large, capital-intensive projects under an innovative energy resource plan. More geothermal, hydro, coal, co-generation, wind and nuclear energy, together with gas from a variety of new sources—all combine to provide one of the most diversified energy systems anywhere.



Finance

Operating revenues for 1980 increased 20 percent over 1979, while operating expenses rose 22 percent over the prior year.

These increases in revenues and expenses reflect higher rates charged customers and higher costs to the Company for natural gas, fuel oil and virtually all other costs of doing business.

Net income for the year came to $525 million, an increase of $67 million over 1979. After preferred dividend requirements of $109 million, $416 million was available for common stockholders, equivalent to $3.60 per share. This was an increase of five cents over the $3.55 per share of a year ago.

The Company's financing program during 1980 totaled $867 million and was the largest and most expensive in PG&E's history. Details of this program, plus further description of 1980 operating revenues, operating expenses, and net income are included in our Management Discussion on Pages 25 through 27.

Revenues and Rates

Operating revenues were $5.26 billion in 1980, up approximately $900 million from the $4.36 billion recorded in 1979. The increase was due entirely to the effect of higher rates, since lesser volumes of gas and electricity were sold in 1980.

The higher rates resulted from the net effect of eight rate increases and one rate decrease ordered by the California Public Utilities Commission at various times during 1980.

Most of these rate adjustments were "offsets" designed to pass along to customers dollar-for-dollar the costs incurred by the Company for the purchase of fuel oil, natural gas, and electric power produced by others.

These so-called "fuel-related" costs comprise the largest single category of expense in the Company's operations, and required 63 percent of all revenue collected from our customers in 1980.

The net additional revenues realized from the "offset" type adjustments during 1980 amounted to approximately $770 million.

A general rate increase authorized in the amount of $201 million to cover higher non-fuel-related costs, such as those for labor, materials, and return on invested capital, contributed only about $130 million when combined with reduced electric sales.

The general rate increase was intended to give the Company an opportunity to earn a return of 13.6 percent on common stock equity investment over the two year period, 1980-1981. However, inflation-induced cost increases, and lower than anticipated sales rendered the general rate increase totally inadequate to permit realization of the aimed-for 13.6 percent return.

Accordingly, the Company applied for an interim general rate increase in 1981. This was granted by the CPUC in February 1981 in the amount of approximately $155 million.

For 1982, PG&E has requested a general rate increase of approximately $1.3 billion. This case is designed to improve the Company's cash flow and requests a 17 percent return on common equity. Hearings will commence in March and a decision is expected by year-end.

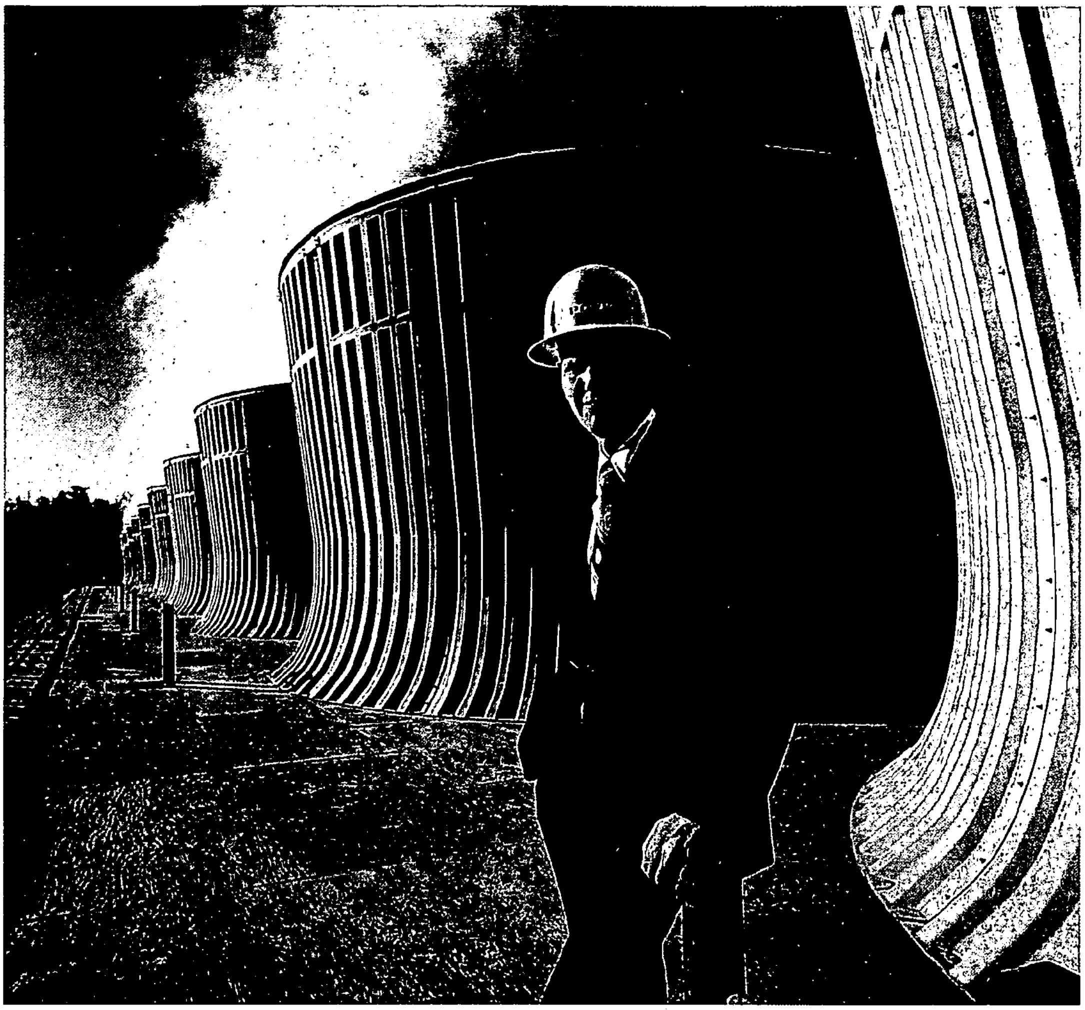
**PG&E is the world's leader in developing geothermal energy.
Richard A. Draeger, Manager, North Bay Division (San Rafael)**

The unusual diversity of the PG&E service area has opened the way for the Company to employ a variety of energy sources, including geothermal steam.

The Geysers is the nation's first commercial geothermal power plant. Its 15 generating units make it the world's largest.

Here atop a cooling tower, is Division Manager Dick Draeger. His staff oversees the production of more than 900,000 kilowatts of electricity—more than five percent of the PG&E area's generating capacity.

When expanded to almost two million kilowatts by 1990, the project will produce as much electricity as the burning of about 20 million barrels of oil a year in conventional steam-powered generating plants.



Electric Operations

Nuclear
Our application to the federal Nuclear Regulatory Commission for permission to load fuel and proceed to low-power testing of Unit 1 of our Diablo Canyon Nuclear Power Plant is still pending.

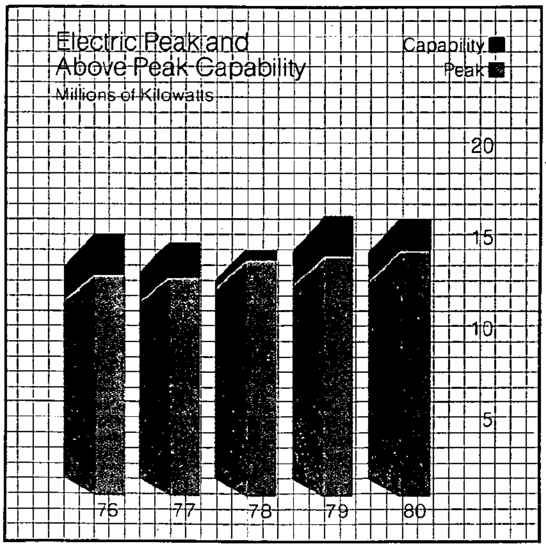
Once in full operation, the two-unit Diablo plant will reduce greatly our use of fossil fuels and save our customers hundreds of millions of dollars each year in lower electric rates.

Geothermal
Two geothermal units, including the world's largest, were added to The Geysers during the year.

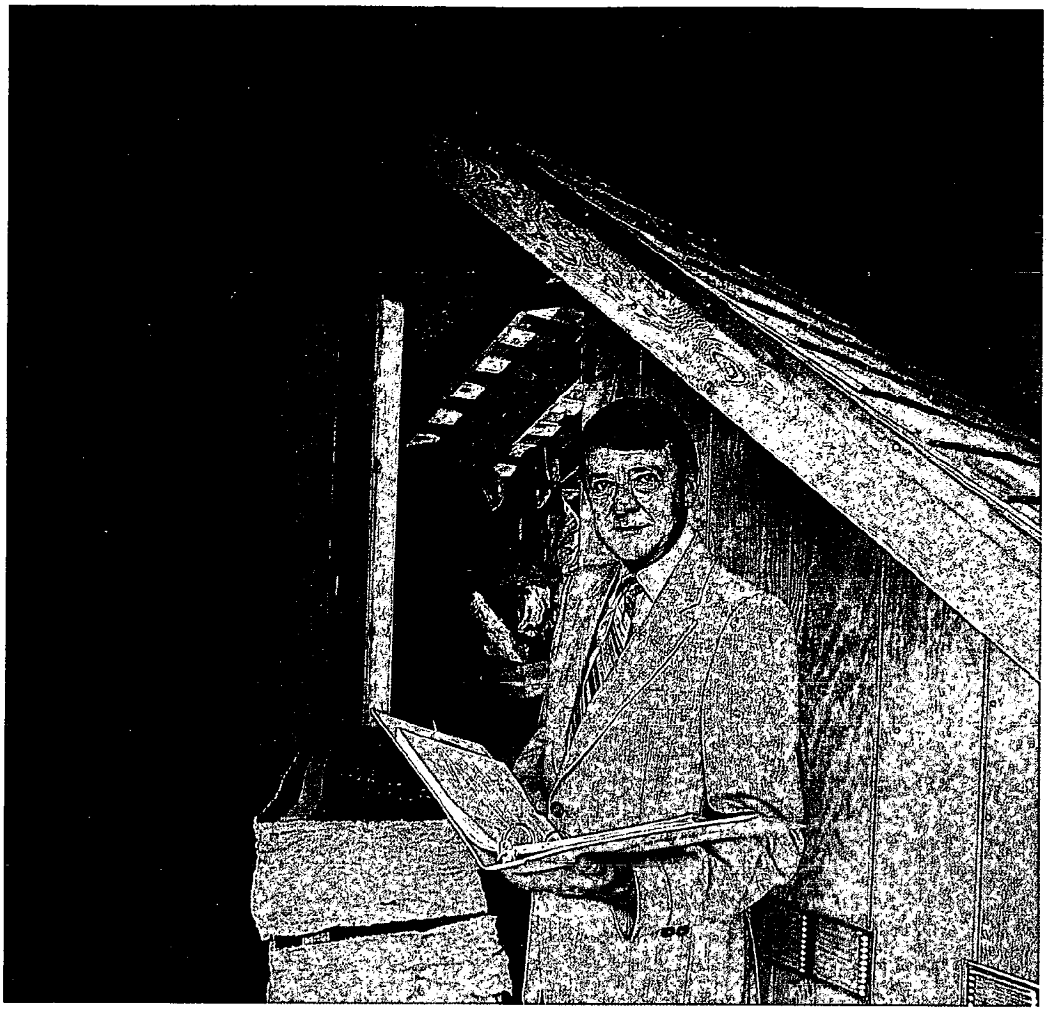
The total electric generating capacity from PG&E's 15 units at The Geysers now stands at 909,000 kilowatts, making this the world's largest geothermal plant.

Nine PG&E units now planned or under construction will increase the plant's capacity by 1990 to 1,789,000 kilowatts.

Hydroelectric
The 1,120,000-kilowatt Helms Pumped Storage Project is now 54 percent complete. During 1980, turbine-generators and other major items of equipment were



Weatherization training center teaches people conservation skills.
C. Robert Martin, Manager, Stockton Division

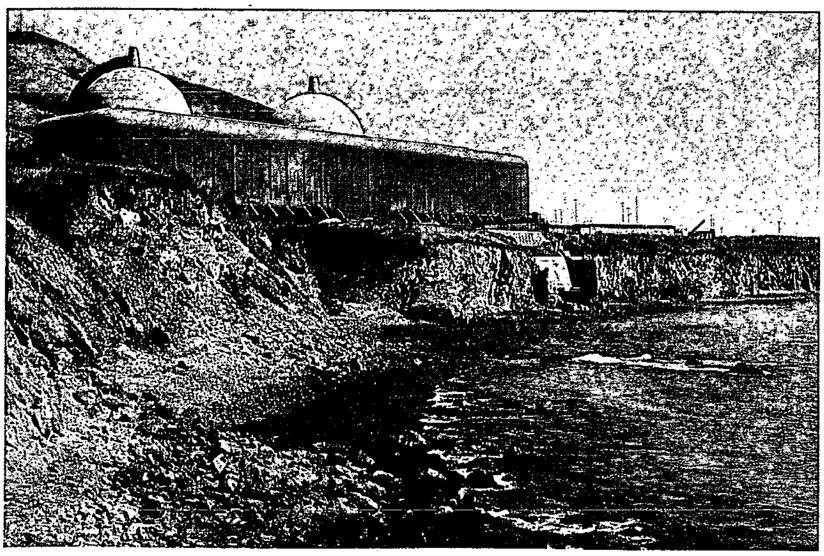


The Company, in an unusual business-local government joint venture, is helping low-income, elderly and disabled persons to conserve energy and to reduce the strain on limited budgets caused by today's energy prices.

Here, at PG&E's training center in Stockton, persons employed locally under the federal Comprehensive Employment and Training Act (CETA) are trained to install attic and other insulation, perform weather-stripping and make minor household repairs.

This center in Division Manager Bob Martin's division turned out 648 trainees during 1980 and class reservations were booked well into 1981.

New classes, including a solar training program, are being offered, also, to PG&E employees, other utilities, private contractors and government agencies.



moved to the site where installation presently is under way in a large underground powerhouse.

Work began in 1980 on another hydroelectric facility — the 140,000-kilowatt Kerckhoff 2 Powerhouse on the San Joaquin River.

The Diablo Canyon Nuclear Power Plant, now being readied for operation, will reduce fuel oil requirements, cut energy costs and provide needed new generating capacity.

Small hydro facilities again have become practical and cost-effective as the cost of fossil fuel to generate electricity keeps rising.

During the past two years, four small PG&E hydroelectric plants on Battle Creek, near Red Bluff, were modernized and their capacity increased. Eight other small hydro units are in the planning stage.

The Company buys power from nine

Looking ahead, the Company is laying the groundwork to strengthen its interconnections with the hydroelectric capacity in the Pacific Northwest, as well as with Nevada, Utah and Idaho, and southward to Southern California and Arizona.

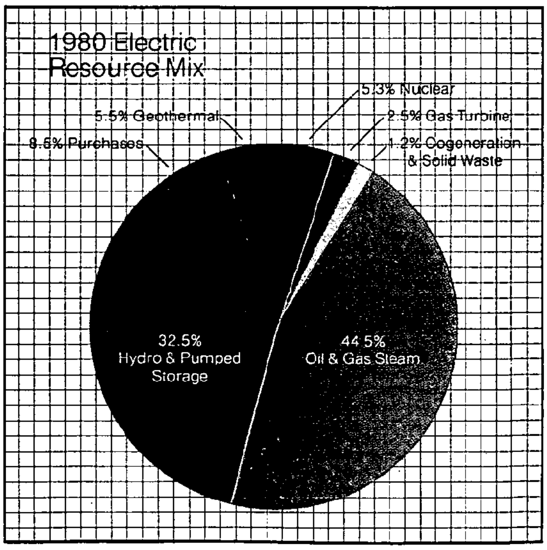
Strong links with other utilities increase system reliability, help to meet summer peaks and permit cost-saving exchanges of energy that further reduce PG&E's dependence on foreign oil.

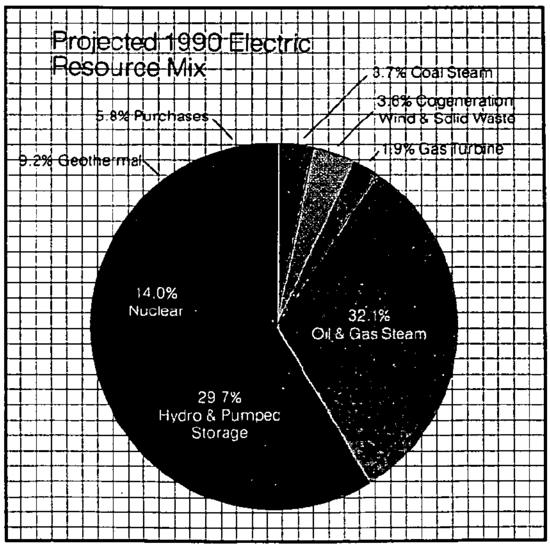
At right, Lou Kirkegaard follows a path through his division where the 500,000-volt Pacific Northwest-Southwest Intertie links the great hydroelectric plants of the Columbia River Basin with the large thermal generating facilities of California.

Strong interconnections with other utilities aid system reliability.
J. Lewis Kirkegaard, Manager, Colgate Division (Marysville)

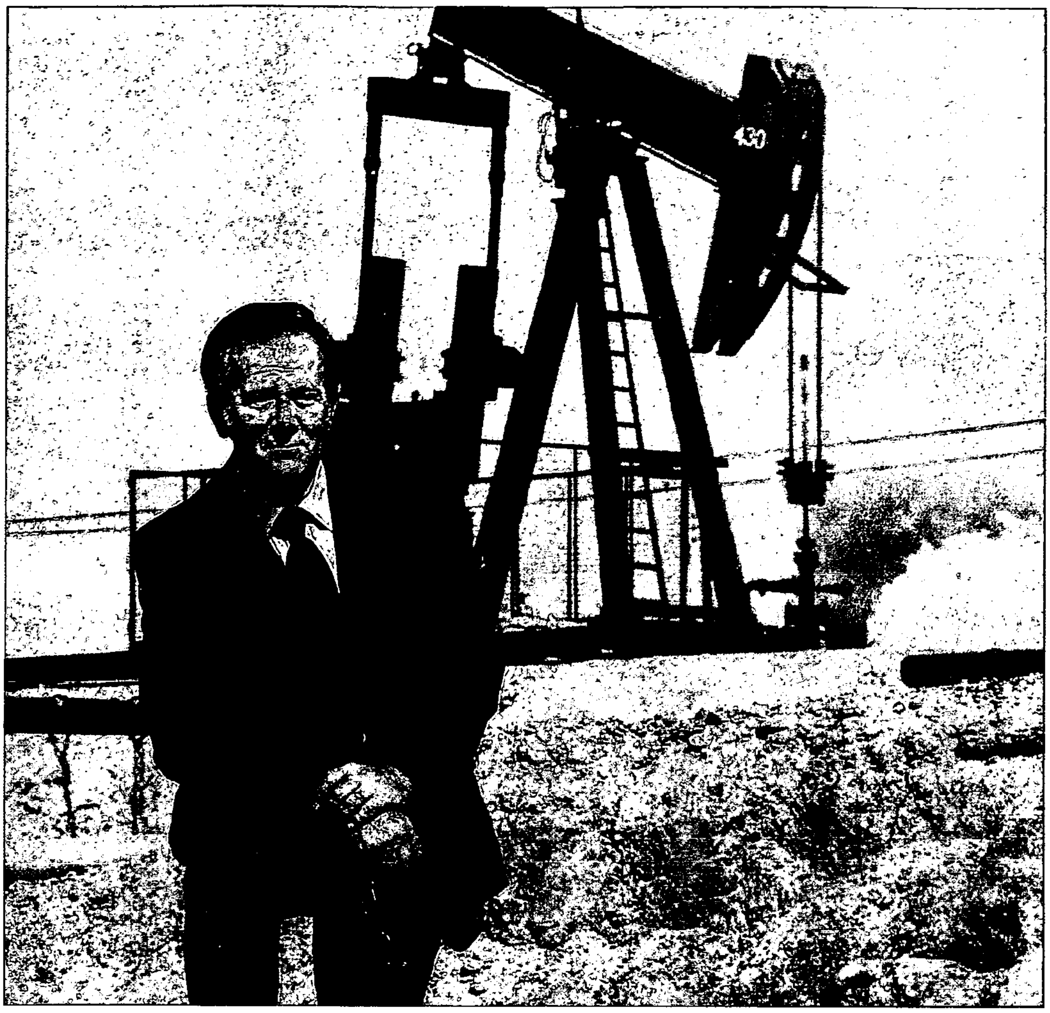
hydroelectric generating facilities belonging to public agencies, such as irrigation and water districts. Negotiations are underway to buy the output of 12 others, under con-

The PG&E Area resource mix, shown at right, includes the PG&E System plus the Sacramento Municipal Utility District and other publicly owned electric systems in Northern and Central California, all of which are electrically integrated with PG&E.





Oil field cogeneration: electric generation combined with enhanced oil recovery.
Grant N. Radford, Manager, San Joaquin Division (Fresno)



In California, oilmen pump steam into oil wells to recover the almost tar-like petroleum common to the state.

While this expensive technique is not new, coupling it with an electric generating source is.

On sites like this, visited by Divison Manager Grant Radford, 11 turbine-generators powered by natural gas or residual fuel oil will produce power for PG&E. Hot turbine exhaust will generate steam for injection into the oil producers' wells.

This PG&E division, covering most of the 200-mile-long San Joaquin Valley, serves much of the state's rich agricultural area.

Its 17,000 square mile electric service area makes it geographically larger than most U.S. energy utilities.

During a recent on-site inspection, Chairman Frederick W. Mielke, Jr., at left, reviewed the major actions taken to enhance safety systems and operator training at Diablo Canyon.

struction or planned.

Cogeneration/ Wind

At the end of 1980, the Company had contracts or other commitments from industrial customers to acquire the output of 14 cogeneration and solid waste electric generation projects with a total capacity of about 200,000 kilowatts. Negotiations are underway for 31 more such projects.

During the past year, the Company connected to the PG&E system five small wind-powered generators owned by customers. And a successful wind-monitoring program led to a Company

Energy conservation and community spirit are at the heart of a two-year electricity management program sponsored by PG&E in Davis, Merced and Chico.

Each community competed to reduce summer peak electric use and win Company awards of energy conservation goods and services for use in civic projects.

Reductions during the summer of 1980 ranged from 13 to 22 percent.

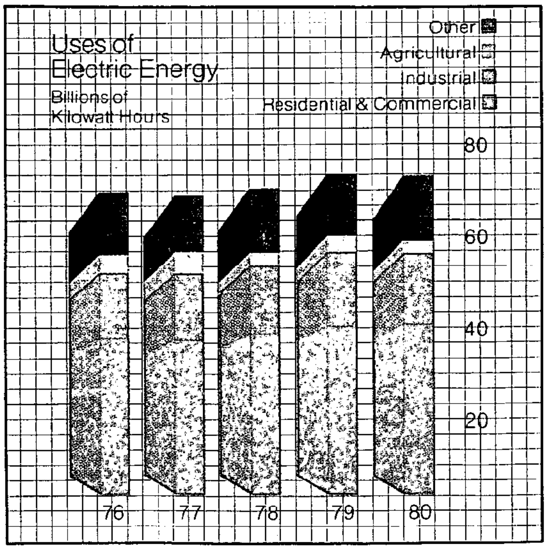
Shown at right, Division Manager Bob Mullikin co-hosts a park full of young people, senior citizens, and other residents of the greater Chico area, all of whom joined in this unique pilot program to increase energy conservation.

More than ever, sponsoring community programs is a PG&E hallmark.
Robert D. Mullikin, Manager, De Sabla Division (Chico)

decision to install a 2,500-kilowatt wind turbine-generator in Solano County.

Coal/Combined Cycle

Because of lower forecasts of growth, plans to seek approvals for a coal-fueled generating plant at the Company's Montezuma site on the Sacramento River, and for a combined-cycle oil or gas-fueled plant at the Potrero site in



San Francisco, were deferred.

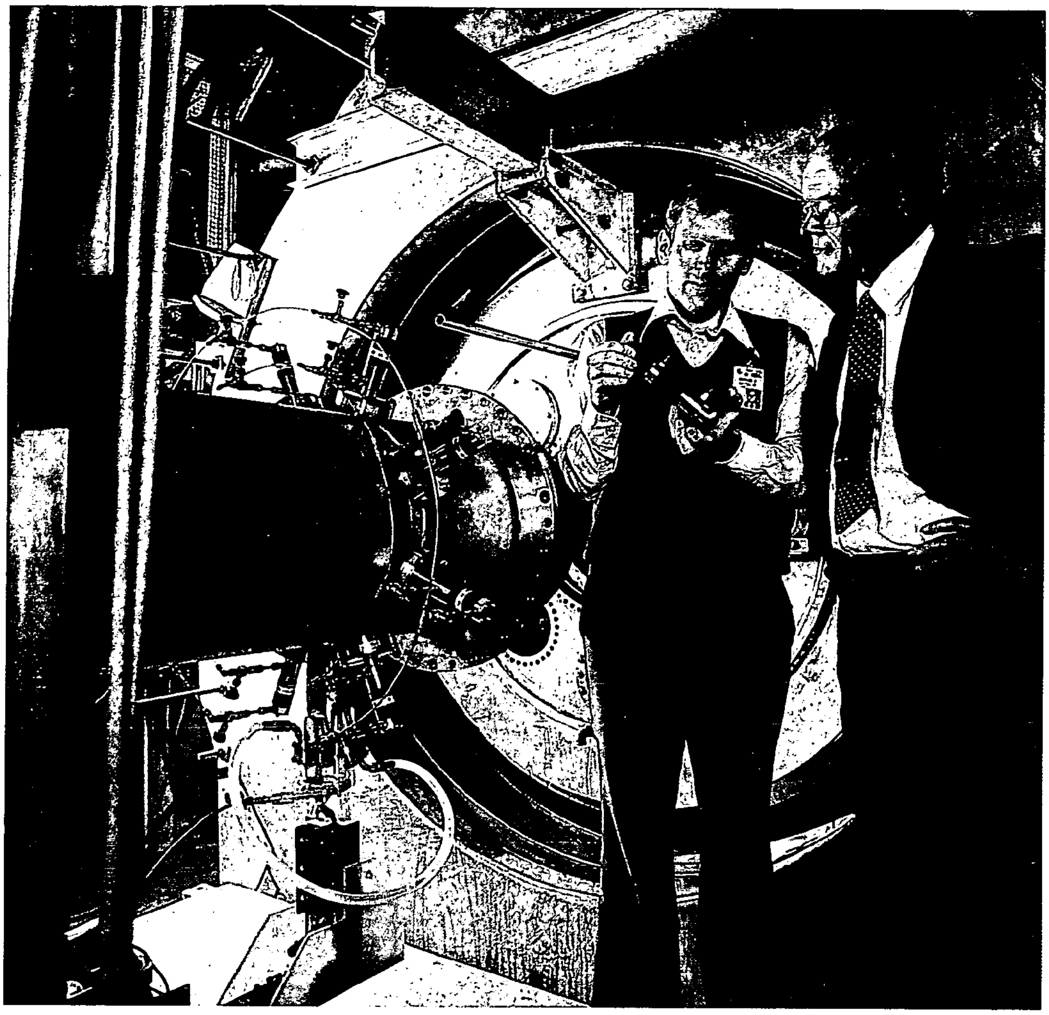
The Company is proceeding on a delayed basis with plans for joint development with other utilities of an out-of-state coal-fueled generation project.

Solar Cell Test Program

At year's end tests were under way at PG&E's engineering research laboratory on photovoltaic solar cells which the Company expects will be a source of power within two years for such things as data recording equipment at remote meteorological sites. By 1984, solar cells may be put to a variety of other uses, including power for agricultural irrigation pumps.

PG&E is helping to fund a Westinghouse facility that will mass produce photovoltaic cells and lower their costs.

Nuclear fusion—one of many areas of research where PG&E is active. George F. Clifton, Jr., Manager, East Bay Division (Oakland)

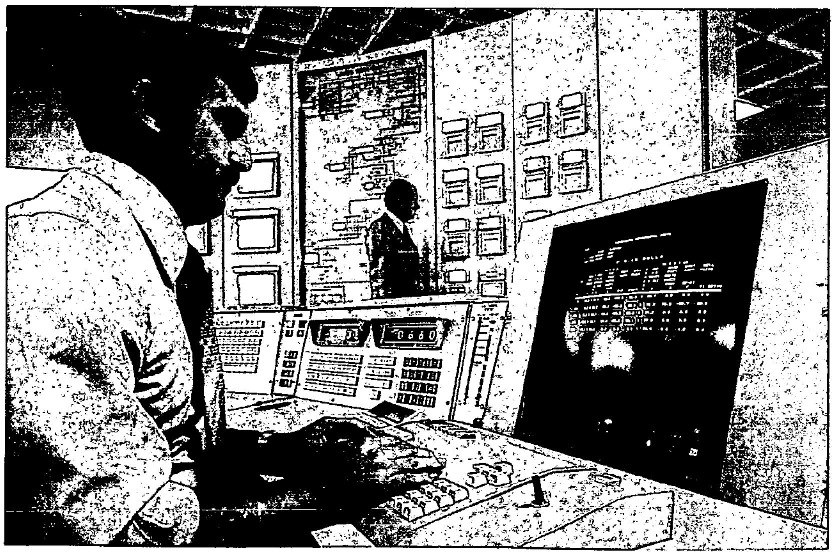


Limitless energy on earth using isotopes of hydrogen — that's the potential seen by proponents of nuclear fusion.

Fusion has been called the most difficult scientific-technological project ever undertaken by mankind. Nevertheless, government and industry—including individual utilities such as PG&E — are making progress in research.

Division Manager George Clifton talks to PG&E Engineer A.C. "Chip" Smith, who has been assigned by the Company to a magnetic fusion experiment at the Lawrence Livermore Laboratory.

Based on power sales, revenues and number of customers served, the East Bay Division—scene of busy port, rail, mill and oil refining activity—would rank among the top 50 electric utilities in the U.S. if it were a separate company.



A new, sophisticated computer link with neighboring power systems instantly tells operators in Power Control the availability and best price for buying or selling electricity to meet customer demands.

Power Sharing
A statewide contingency plan for power sharing to protect Californians from electric shortages during peak use periods was approved in May by the California Public Utilities Commission.

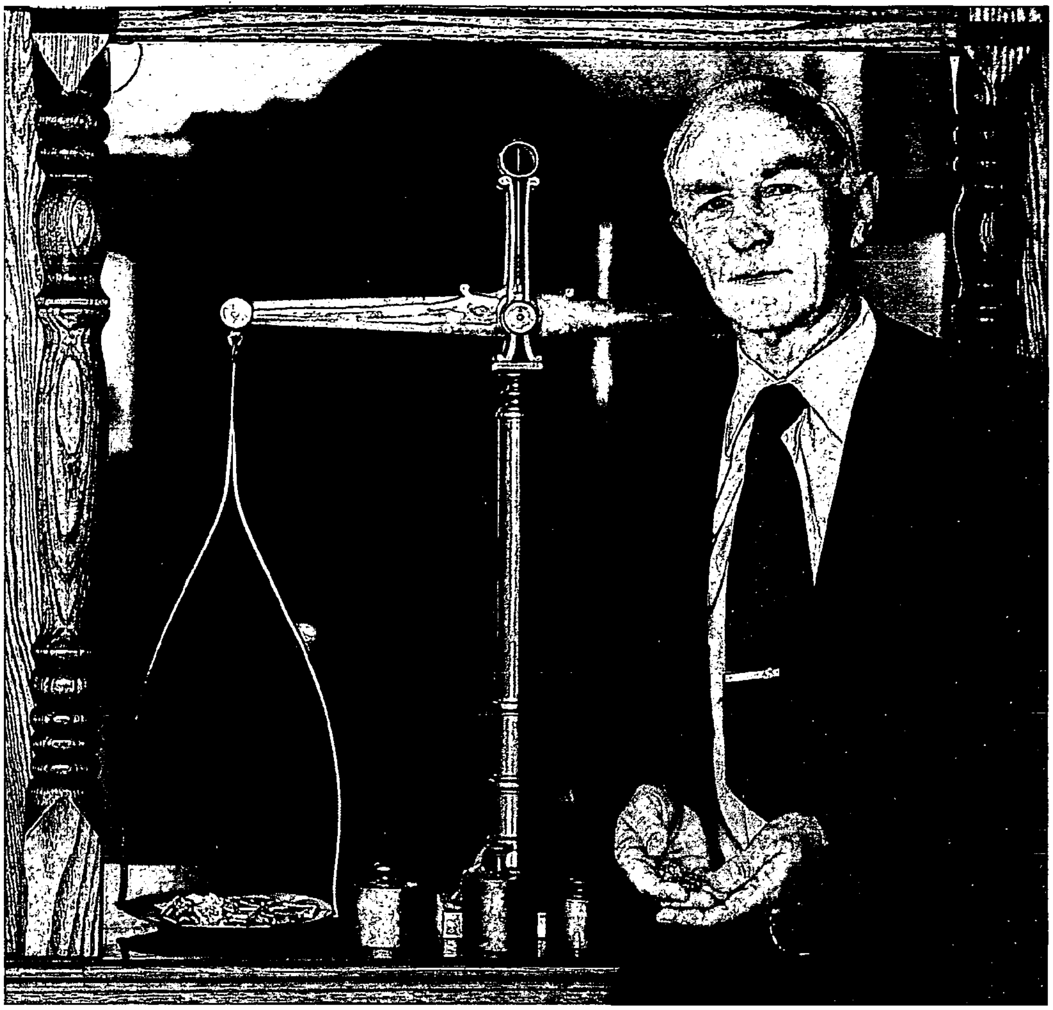
The plan was placed under the direction of PG&E President Barton W. Shackelford. He is also the coordinator of a three-stage emergency plan to reduce customers' loads should the combined generating reserves available to California power systems fall below acceptable levels.

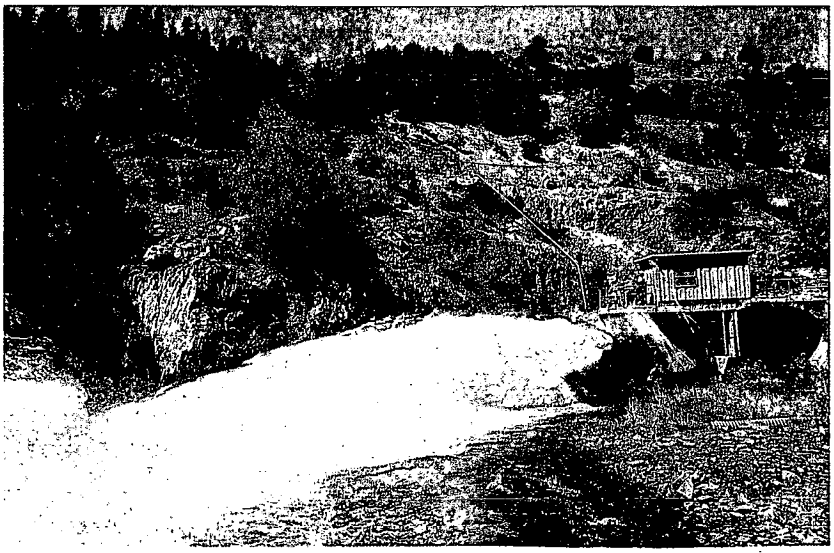
Efforts to reduce the use of expensive oil and natural gas to generate electricity include plans by this and several other PG&E divisions to build and operate small hydroelectric power plants, or to buy power from similar units owned by others.

The Company's service area also contains the largest remaining gold deposits in the United States, according to the U.S. Bureau of Mines.

As gold prices increased, many old mines were reopened and a new California gold rush was under way. One of the areas attracting a new breed of prospectors and increased mining activity is near Nevada City. Here Division Manager Bob Metzker, visits the local mint where gold nuggets are being weighed.

Hydro power, gold mining expansion underway in California.
Robert E. Metzker, Manager, Drum Division (Auburn)





Efforts to reduce the use of expensive oil and gas to generate electricity include installing small hydro plants and buying power from similar units owned by others.

Gas Operations

Alaska Gas

Construction began in December on the Western Leg of the proposed 4,800-mile, Alaska Natural Gas Transportation System which will bring Alaska gas to the lower 48 states.

The Western Leg will be built by the Company and its subsidiary, Pacific Gas Transmission Company, by paralleling the existing pipeline which brings Canadian gas to PG&E.

Until the Alaska pipeline is completed, the Western Leg will transport Canadian gas for delivery by PG&E to Southern

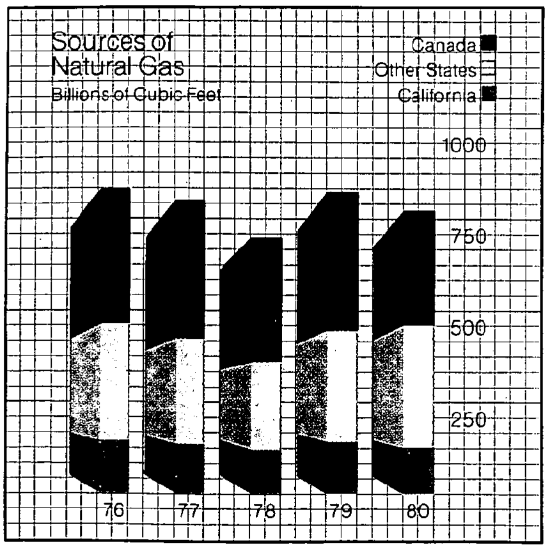
Another new PG&E energy source – gas from garbage in sanitary landfills.
Vernon H. Lind, Manager, San Jose Division

Methane gas tapped from a sanitary landfill in Mountain View, south of San Francisco, is now being mixed with traditional gas in the Company's pipelines. It's a useful supplement to the average of 2.1 billion cubic feet of natural gas a day presently supplied to PG&E customers.

Now in its third year, the project being inspected here by Division Manager Vern Lind is proving the commercial feasibility of this alternate energy source.

Additional wells at this site and at 13 other Bay Area sanitary landfills could provide a combined methane gas output equivalent to about 12 million cubic feet a day of natural gas, enough to serve about 58,000 average homes.

The San Jose Division – center of booming aerospace and electronic industries – would rank 37th among the top 100 U.S. electric utilities based on the number of customers served.



California Gas Company, commencing in 1982.

Rocky Mountain Gas

The Company is engaged, through its subsidiaries, in gas exploration in the Rocky Mountain area, including the Overthrust Belt.

As a result of gas discoveries from this program and anticipated purchase or development of additional gas, the Company's subsidiary, PGT, has joined with El Paso Natural Gas Company, Southern California Gas Company and Northwest Pipeline Corporation in a partnership to construct a 583-mile pipeline from this area to California. Authorization to proceed with this $515 million project is pending before the Federal Energy Regulatory Commission.

California Gas

In 1980 the Company's subsidiary, Natural Gas Corporation of California (NGC), added new California gas reserves to the PG&E system as a result of drilling nearly 20 percent of all the exploratory wells drilled in the Sacramento Valley – the main gas-producing area of the state.

A major function of California gas reserves is to protect high priority residential

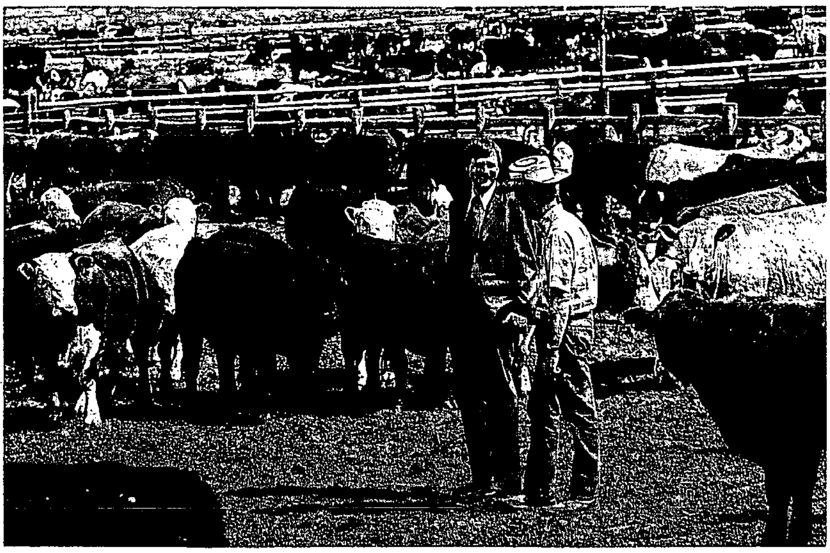
Growers and cattlemen generate $14 billion a year in new wealth and create one out of every four jobs in California.

A major share of the state's crop production comes from nine million acres where, each year, water pumps consume five billion kilowatt hours of electricity to irrigate the land.

Since 1923, Company agricultural specialists and pump testers have helped farmers use energy more efficiently.

Today, there's a new dimension to this utility-customer partnership. Here, Division Manager Floyd Marks explains innovative programs to help agribusiness cut energy costs by conserving and by taking advantage of lower rates charged for use during off-peak hours.

Specially designed conservation programs help California agribusiness.
Floyd C. Marks, Manager, Coast Valleys Division (Salinas)



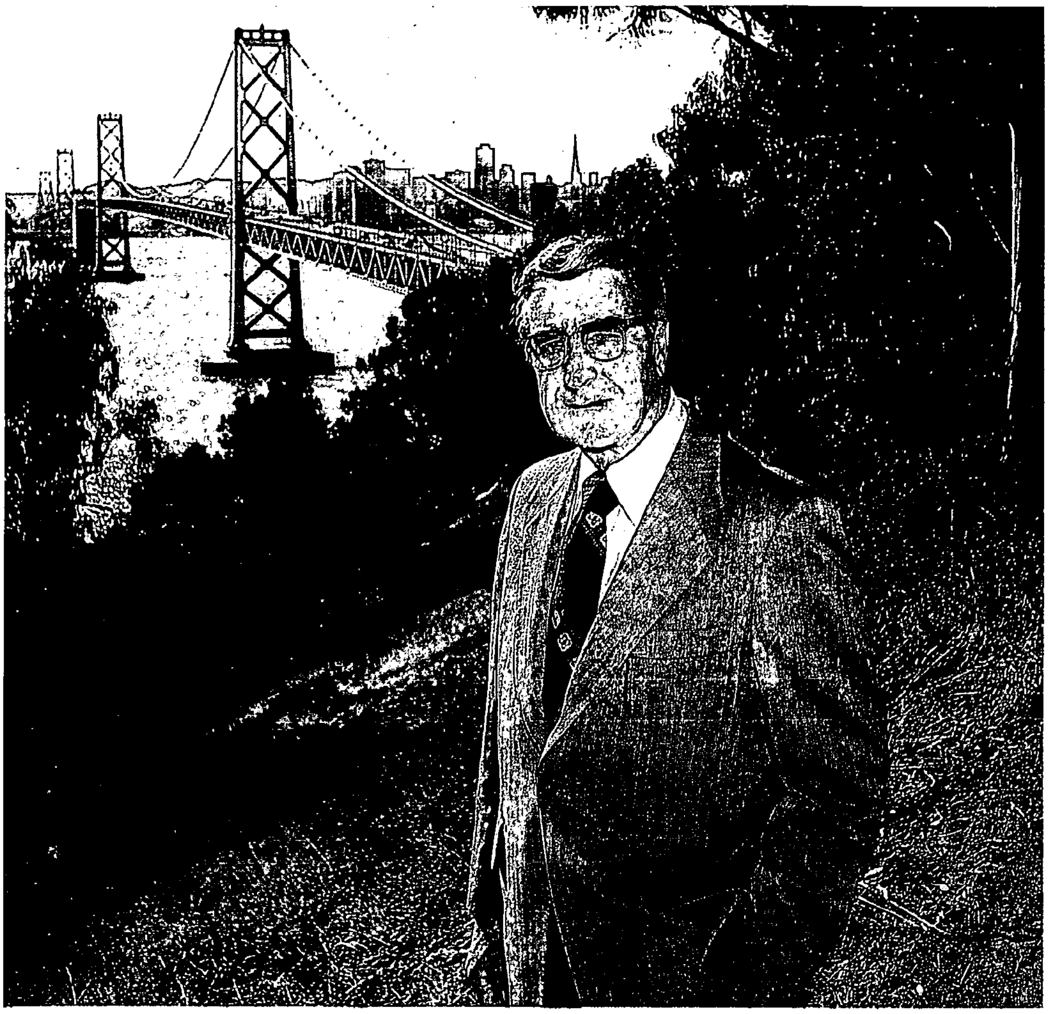
customers during times of peak demand. In view of rising costs of Canadian gas and the record of success achieved by NGC in exploration, the Company will continue to seek regulatory approvals for the financing of further California exploration.

Two years of pilot plant operation indicate that methane gas produced from cattle feedlot waste could become another source of energy for PG&E gas customers.

Coal Gasification
PG&E's current resource plan anticipates receiving 60 million cubic feet of synthetic natural gas (SNG) a day by 1986 and double this amount by 1991.

In November, the Company signed a letter of intent with Panhandle Eastern Pipe Line Company and Ruhrgas Aktiengesellschaft of Essen, West Germany, to pursue joint development of SNG from

Birthplace and headquarters of PG&E is the City of San Francisco.
J. Art Fairchild, Manager, San Francisco Division



Spanning one of the world's great harbors, the eight-mile Bay Bridge links San Francisco with more than 20 cities along the eastern shore that contribute vitality to this unique metropolis.

But bridge and distant skyline, shown here from mid-bay Yerba Buena Island, can only hint at the matchless physical setting, mix of cultures and bustling commercial activity of this PG&E division headed by Manager Art Fairchild.

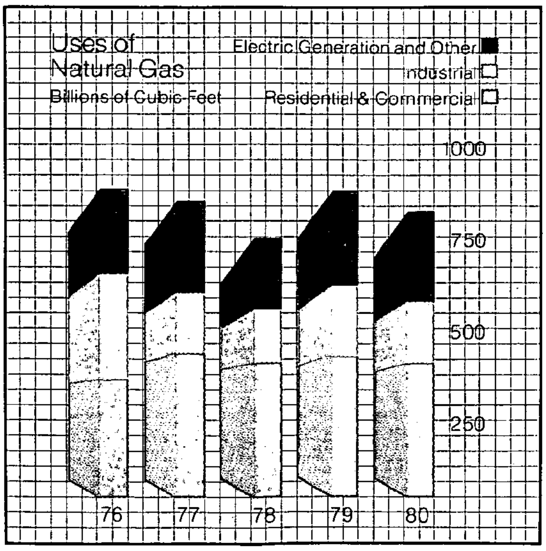
While high-rise towers speak of San Francisco as the financial center of the west and gateway to the Pacific Basin, other attractions—the delights of Nob Hill, cool summer fog, cable cars, hotels preserving past splendors, shops and restaurants of every kind—all have made the city a magnet for tourists from everywhere.

It was here that gas and electricity first came to California soon after the 49ers.

coal near Douglas, Wyoming. The output of this project could reach 300 million cubic feet a day of SNG by 1993.

PG&E, together with Texaco, Inc. in December received a federal Department of Energy grant of more than $4 million partially to fund a feasibility study of a coal gasification—cogeneration project at San Ardo in Monterey County. Should this project prove economically feasible, it would become the largest cogeneration facility in California.

Using the synthetic gas as fuel, turbine-generators would provide up to 210,000 kilowatts of electricity for the PG&E system. Exhaust heat would be captured to produce steam for injection into wells to facilitate Texaco's recovery of heavy crude oil.



Liquefied Natural Gas (LNG)

Because of escalating costs, regulatory delays, and the need to allocate available capital resources among a number of projects, PG&E is seeking additional partners to share ownership in a gas liquefication plant in Alaska and in tankers to bring Alaska LNG to California.

PG&E's partner in this project, Pacific Lighting Corporation,

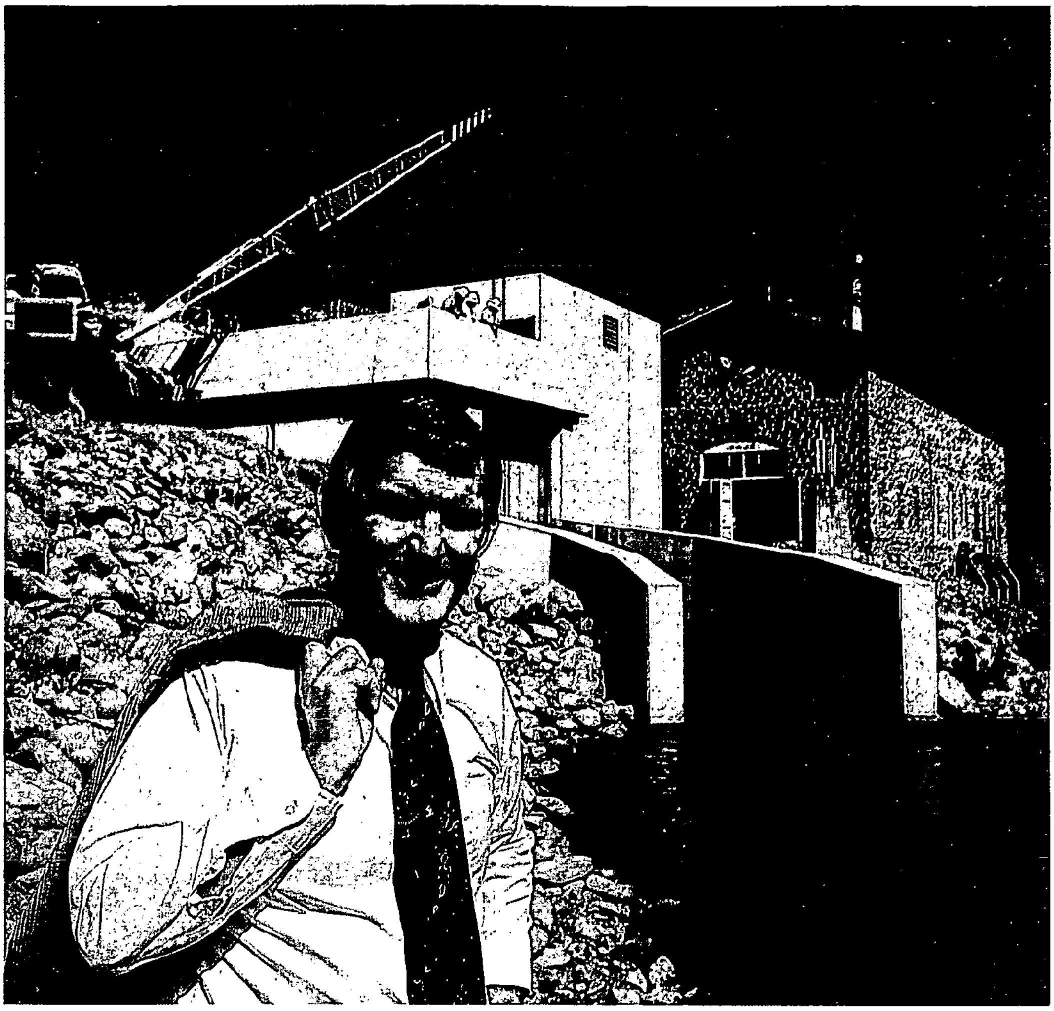
As the cost of new electric generating facilities soars, modernizing and upgrading existing power plants often makes economic sense.

Typical is the 70-year-old Inskip hydroelectric powerhouse, now reconstructed to generate as much as 25 percent more electric power from the same water facilities.

Inskip is but one of three picturesque, stone powerhouses built between 1901 and 1910. Improvements to our Battle Creek hydro system added 7,600 more kilowatts in this Northern California division managed by Jack La Rue.

And elsewhere throughout PG&E more hydro is on the way, ranging from a huge pumped storage project to small plants located wherever it is feasible to capture the force of falling water.

Modernizing older hydroelectric plants can add 25 percent more capacity.
R. J. La Rue Jr., Manager, Shasta Division (Red Bluff)



has joined in this effort.

Because a California LNG receiving terminal is vital for access to gas reserves in the Pacific Basin, particularly Alaska and Indonesia, the Company remains optimistic that the Little Cojo Bay terminal site near Point Conception on the Central California coast will receive final regulatory approvals by the end of 1981.

A two-year seismic study of this site is under review by the California Public Utilities Commission and the Federal Energy Regulatory Commission as a last

Ten feet of snow carpet a Sierra meadow, scene of one of the more unusual of the 2,100 different jobs performed by PG&E employees. Here, a survey team measures the depth and water content of the snow pack. Ample runoff means more hydro generation; less need for burning costly foreign oil in thermal power plants.

California waters yield more than a billion pounds of fish each year.
Roy C. Atkins, Manager, Humboldt Division (Eureka)

Commercial and sport fishing, tourism and magnificent redwoods – famed for their towering majesty and for their yield of highly prized lumber and wood products – combine to fuel the economy of California's north coast.

Much of the state's energy-dependent fishing industry prospers in close relationship with the Company. Here, Division Manager Roy Atkins observes newly caught salmon about to be processed in Eureka.

There, a number of Company-sponsored conservation programs help canners use gas and electricity more efficiently.

Nearby lumber mills, consuming vast amounts of steam and electricity, more and more team with PG&E in cogeneration projects using biomass fuel.

step in determining site acceptability.

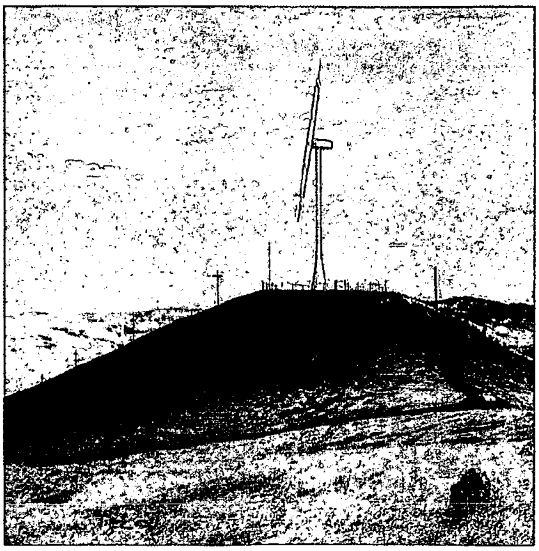
Given unconditional approval of the receiving terminal site, favorable resolution of court appeals, and securing of additional partners, delivery of LNG could start by 1987.

Methane
PG&E's efforts to tap methane,the principal component of natural gas, from sanitary landfills advanced during the year.

The Department of Energy in October announced that it will fund a feasibility study on the cost of designing a commercial system to produce pipeline quality gas from sanitary landfills at Mountain View in Santa Clara County and Calabasas in Los Angeles County.

The $341,820 award, subject to final negotiation, came in response to application by PG&E and Southern California Gas Company.

In addition, DOE granted $328,900 to fund further study of a cattle feedlot project of the two companies in the Imperial Valley. This project is testing



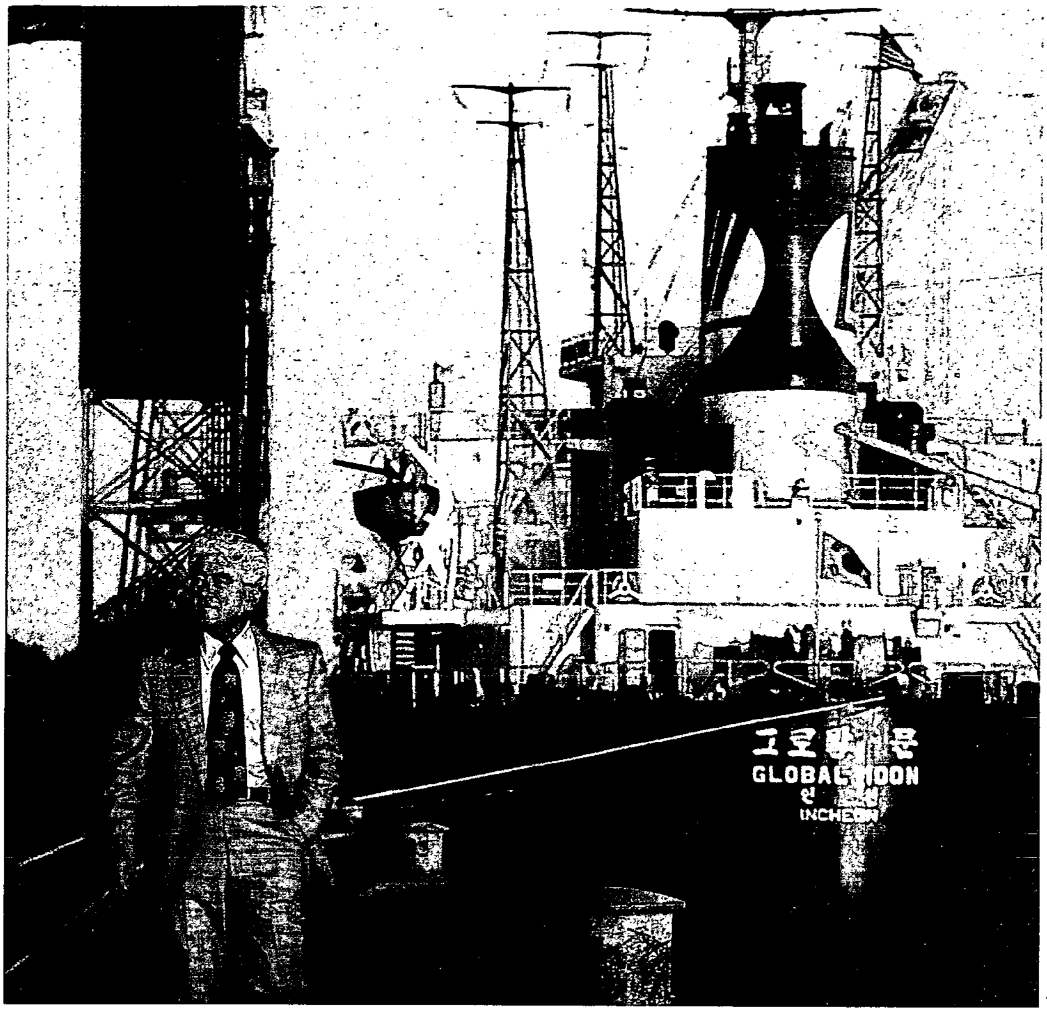
PG&E's commitment to develop alternate sources of energy is shown in this artist's conception of the Company's first wind turbine-generator, due for operation in 1982.

In a service territory as varied as Northern and Central California, it is not surprising that Manager Stan Howatt is involved in the expansion of a port located on a deepwater ship channel 80 miles inland from San Francisco.

Here at the Port of Sacramento, a new $10 million bond issue will finance additional cargo and storage facilities to handle exports of rice, wheat, logs, wood chips and fertilizers worldwide. Such facilities, of course, will require additional dependable energy from PG&E.

Division managers prize the Company's ability to provide on schedule new energy service to industrial, commercial, agricultural, and residential customers.

Inland port development goes on deep in the heart of our service area.
Stanley E. Howatt, Manager, Sacramento Division

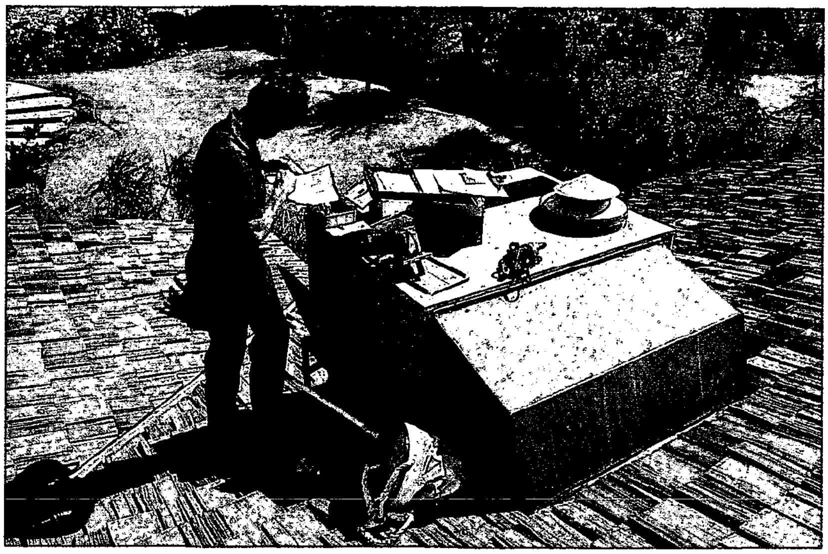


the commercial feasibility of using manure to produce commercial quantities of methane.

Preliminary studies show that the production of 1.8 million cubic feet of methane per day is possible, an amount that would meet the annual needs of about 7,800 average Northern and Central California homes.

Energy Conservation

During 1980, PG&E spent about $37 million to help its residential, commercial, industrial and agricultural customers use natural gas and electricity more efficiently.



In certain areas, residential customers practice conservation by allowing PG&E to install remote control devices which can turn off air conditioners on a rotating basis during peak load hours.

A like amount flowed into Company programs to develop alternate fuels using solid waste and biomass, co-generation, load management, voltage reduction and energy-saving street light conversion. Programs also were designed to reduce the Company's own energy use.

All in all, more than 50 separate programs saved the energy equivalent of burning an estimated eight million barrels of $30 fuel oil ($240 million worth) to generate electricity. Put another way, savings represented enough energy to serve 50,000 homes with electricity, or 67,000 homes with natural gas, over the next 10 years.

For developing and promoting these successful programs over the past four years, PG&E in January received a White House award "for outstanding contribution to the national energy conservation effort."

Focal point of PG&E's energy conservation programs is an Energy Conservation Center, which during 1980 responded to nearly 150,000 toll-free telephone inquiries from customers seeking information on subjects such as insulation, weather-stripping, lighting conservation and appliance efficiency.

More than 3,000 on-site audits were performed for commercial, industrial and agricultural customers, as well as for government facilities and schools.

About 62,000 residential home energy audits were made during 1980.

Early in 1981, the California Public Utilities Commission approved the initial phase of an innovative PG&E proposal to offer zero interest program (ZIP) financing for installation of insulation, weather stripping, or other cost effective conservation devices in homes.

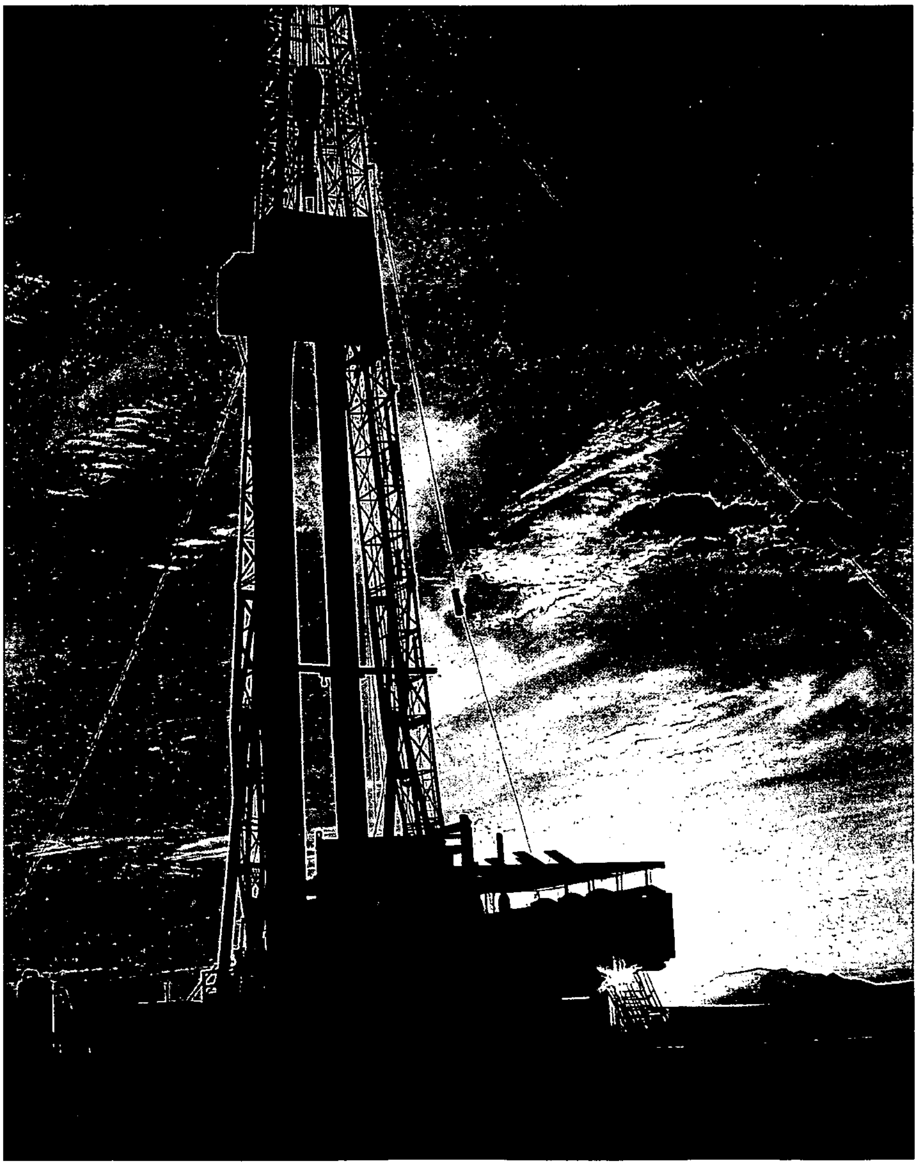
By far the largest such undertaking by a U.S. utility, ZIP offers home-owners and residential landlords the chance to pay for conservation measures with interest-free loans. The first-phase of the program will start soon in 10 counties in the Fresno-San Joaquin Valley area.

Under these cost effective conservation programs, the Company obtains energy at less cost than providing new energy supplies. This benefits all customers and benefits stockholders by lessening the need to finance the development of new energy supplies at high capital costs which depress earnings.

Another endeavor is a Solar Financing program designed to determine the cost effectiveness of putting solar water heating systems in homes and rental units. The plan would be available on a first-come, first-served basis and customers would be allowed to choose from a variety of financing methods. More than 800 low-income customers will receive free solar water heating systems from PG&E under a plan developed by the CPUC.

During 1981, the Company plans to spend more than $115 million on its overall conservation activities. These will involve about 1,100 employees delivering services through some 60 programs to 3.4 million electric and 2.8 million gas customers.

Experience during the past four years makes it clear that, with a management committed to conservation, along with highly skilled and dedicated employees working with



Sunset frames a drilling rig in Wyoming — a reminder that the sun seldom sets on all the employees of PG&E and its 14 subsidiary and affiliated companies. Buyers, quality control inspectors and employees seeking new sources of natural gas range nationwide and often worldwide.

customers, the people of Northern and Central California will continue their already-serious efforts to reduce energy waste.

Our Employees

Some 18,500 of our more than 27,000 employees are represented by the International Brotherhood of Electrical Workers (AFL-CIO) and 2,000 by the Engineers and Scientists of California.

More than 6,800 minority personnel are employed by PG&E—24.5 percent of the total workforce. Upward mobility of minorities continues at a rate which now shows 60 percent are in the journeyman level or above.

Approximately 750 women are performing jobs in construction, maintenance and other physical work. Many have advanced into such jobs as service personnel, control operator, substation operator and equipment operator.

Women, too, are moving into management at an increasing rate.

The Company's commitment to provide career development opportunities also reached new highs during 1980 in terms of specialized training programs, workshops, home study courses, and technical and management courses at the college and university level.

The Company carries on a strong recruitment program to attract top engineering, science and business administration graduates.

During the year, pension adjustments and improved medical coverages were made to help PG&E's 5,600 retired employees meet the problems of living on a fixed income during a period of high inflation and spiralling health care costs. This is the third pension adjustment for retired employees since pensions were first raised in 1969.

Employees during 1980 continued a long tradition of service to their communities. Many serve on local government bodies, such as city councils, school boards, and planning commissions or are active with service, youth, civic and charitable organizations.

Executive Changes

Following eight years of service, Doris F. Leonard, internationally respected conservationist, retired as a director in February 1981 under the Board of Directors' age-in-service policy.

L. W. Lane, Jr., chairman of Lane Publishing Company and an advisory director, was elected to fill the vacancy. Mr. Lane, too, has been prominent in areas of conservation and environmental protection.

To add to the Company's organizational strength during these times of increasing demands upon utility management, the Board in February, 1981, elected the following to new senior positions: John S. Cooper, senior vice president—personnel; Malcolm H. Furbush, senior vice president and general counsel; Malcolm A. MacKillop, senior vice president—corporate relations; and George A. Maneatis, senior vice president—facilities development. These officers also become new members of the Company's Management Committee.

Elmer F. Kaprielian was elected to the new post of vice president—fuels planning and acquisition; Robert Ohlbach was elected to the new post of vice president and general attorney; and John F. Taylor was elected vice president and corporate secretary. George F. Clifton, Jr., succeeded Mr. Cooper as vice president—customer operations, and John E. Koehn succeeded Mr. MacKillop as vice president—governmental relations.

William H. Wallace succeeded Mr. Maneatis as vice president—computer systems and services. Richard K. Miller, who has been vice president—personnel and general services, will have the new title of vice president—general services. All of these appointments are effective April 1, 1981.

Other management changes since the Company's last Annual Report include the election in March 1980 of James O. Schuyler, nuclear projects engineer, to the new post of vice president—nuclear power generation, and the election in May 1980 of Treasurer James T. Doudiet to vice president—finance and treasurer.

Lawrence R. McDonnell, vice president—public relations, retired in September 1980 following 27 years with the Company. Grant N. Horne, director of special projects for public relations, was elected to replace Mr. McDonnell.

PG&E campus representatives at California Polytechnic University, San Luis Obispo, guide other students, faculty and living groups in ways to conserve energy. Campus representatives offer customer services on five other Northern California campuses also.

DEPARTMENTAL ORGANIZATION

Electric Operations
Managers:
W. H. Barr, Steam Generation
F. C. Buchholz, Transmission and Distribution
D. H. Colwell, System Protection
T. R. Ferry, Communications
W. A. Flowers, Hydro Generation
E. F. Kaprielian, Power Control
J. N. Ylarraz, Substations

Nuclear Power Generation
Managers:
J. B. Hoch, Nuclear Projects
W. A. Raymond, Quality Assurance
J. D. Shiffer, Nuclear Plant Operations

Gas Operations
Managers:
R. C. Heilmann, Gas Utilization
C. A. Miller, Pipe Line Operations
T. C. Odom, Gas System Planning
F. J. Parsons, Gas Control
W. E. Ross, Natural Gas Production
J. B. Stoutamore, Gas Distribution
C. J. Tateosian, Gas System Design

Gas Supply
J. K. A. Harral, Manager Gas Resources

LNG Companies
K. L. C. Dorking, Vice President and General Manager

Coal Supply
D. W. Hess, Manager

Engineering
Chiefs:
G. H. Aster, Design Drafting
R. V. Bettinger, Civil Engineer
J. F. Herrera, Electrical Engineer
D. V. Kelly, Mechanical and Nuclear Engineer
J. J. McCann, Engineering Services
J. V. Rocca, Engineering Quality Control

Customer Operations
Managers:
R. M. Mertz, Energy Conservation and Services
J. G. O'Neill, Customer Services
J. M. Stearns, Commercial

Geysers Project
R. P. Wischow, Manager

Internal Auditing
E. C. Suess, Manager

Planning and Research
Chiefs:
R. F. Cayot, Engineering Research
E. E. Hall, Generation Planning Engineer
H. M. Howe, Siting Engineer
H. R. Perry, Transmission Planning Engineer

Rates and Valuation
Managers:
S. M. Andrew, Economics and Statistics
H. E. Crowhurst, Jr., Valuation
B. Davis, Revenue Requirements
S. P. Reynolds, Rate

Comptroller
J. W. Hall, Assistant Comptroller
K. S. Taylor, Assistant Comptroller
Managers:
R. C. Bagley, Property Tax
R. W. Beck, Corporate Accounting
A. W. Deige, Disbursements Accounting
H. W. Gleason, Income Tax
L. D. Lee, Plant Accounting
E. M. Schroeder, Customer Accounting

Law
*R. Ohlbach, Associate General Counsel
Assistant General Counsel:
C. T. Van Deusen
P. A. Crane, Jr.
H. J. LaPlante
J. B. Gibson
A. L. Hillman, Jr.
C. W. Thissell
D. E. Gibson

Computer Systems and Services
Managers:
R. W. Barbey, Information Systems
H. N. Liu, Computer Systems Technology
A. W. Simila, Computer Operations
G. M. Rueger, Engineering Computer Applications

Stock Transfer
L. H. Gunter, Manager

Insurance
W. F. Noone, Manager

Treasurer
Managers:
W. M. Cracknell, Credit and Collection
J. E. Helms, Financial Planning and Analysis
G. R. Smith, Banking and Money Management

Personnel and General Services
Managers:
[illegible] Abel, Automotive and Equipment
L. W. [illegible], Industrial Relations
R. H. Cunningham, Personnel Relations
J. W. Page, Land

General Construction
Managers:
R. S. Bain, Station Construction
E. C. Beatland, General Construction Personnel
W. Funabiki, Gas Construction
R. F. Irons, General Construction Services
A. G. Strassburger, Civil-Hydro Construction
W. M. Stubblefield, Line Construction

Safety, Health and Claims
B. P. Sadler, Manager

Materials
R. P. Benton, Manager

Public Relations
Managers:
D. J. Baxter, Public Information
R. H. Miller, Advertising
H. N. Peelor, Public Activities

Governmental Relations
R. B. Dewey, Assistant to the Chairman of the Board
J. E. Koehn, Manager, Governmental and Public Affairs
C. A. Bland, Manager, Agency Relations
[illegible], Executive Representative

President's Office
[illegible], Assistant to the President
A. H. [illegible], Assistant to the President of Project Management Development

DIVISION MANAGERS
Coast Valleys
F. C. Marks, Salinas
Colgate
J. L. Kirkegaard, Marysville
De Sabla
R. D. [illegible], Chico
Drum
R. E. Metzler, Auburn
East Bay
C. F. Clifton, Jr., Oakland
Humboldt
R. C. Atkins, Eureka
North Bay
R. A. Draeger, San Rafael
Sacramento
S. E. Howatt, Sacramento
San Francisco
J. A. Fairchild, San Francisco
San Joaquin
G. N. Radford, Fresno
San Jose
V. H. Lind, San Jose
Shasta
R. J. LaDue, Jr., Red Bluff
Stockton
C. R. Martin, Stockton

*Elected Vice President effective April 1, 1981

Contents

CONSOLIDATED COMPARATIVE STATISTICS

For the Years Ended December 31,	**1980**	1979	1978	1977
Per Common Share				
Earnings	**$ 3.60**	$ 3.55	$ 3.18	$ 3.14
Dividends Declared	**$ 2.60**	$ 2.38	$ 2.16	$ 2.00
Dividend Payout Ratio	**72.2%**	67.1%	67.8%	63.7%
Book Value (end of year)	**$30.09**	$29.83	$29.69	$28.72
Market Price – High	**24¾**	25⅛	24⅞	25½
Market Price – Low	**19¼**	21⅝	21¾	22¼
Market Price – Close	**20½**	23	22¼	24
Construction Expenditures (Thousands)				
Electric Department	**$ 973,785**	$ 943,911	$718,572	$599,126
Gas Department	**247,973**	205,397	140,541	122,198
Total	**$1,221,758**	$1,149,308	$859,113	$721,324
Electric Statistics				
Net System Output (Millions of KWH)	**69,962**	70,339	67,669	65,428
Net System Output – Percent				
Hydroelectric Plants	**19.0%**	16.8%	19.9%	9.2%
Thermal Electric Plants	**50.5**	59.1	49.5	72.4
Other Producers	**30.5**	24.1	30.6	18.4
Total	**100.0%**	100.0%	100.0%	100.0%
System Capacity – KW (at annual peak)				
Hydroelectric Plants (adverse conditions)	**2,354,600**	2,360,000	2,350,900	2,350,900
Thermal Electric Plants	**8,754,000**	8,612,000	8,294,000	8,294,000
Other Producers (adverse conditions)	**3,971,000**	4,112,900	2,791,100	3,302,900
Total	**15,079,600**	15,084,900	13,436,000	13,947,800
Net System Peak Demand – KW	**13,440,400**	13,215,200	12,970,600	12,191,800
Average Annual Residential Consumption – KWH	**6,535**	6,811	6,553	6,408
Total Customers (end of year)	**3,447,739**	3,365,950	3,270,302	3,179,362
Customers Per Mile of Distribution Line	**39.1**	38.9	38.5	38.1
Gas Statistics				
Gas Purchased for U.S. Operations (Thousands of MCF)	**779,980**	841,764	709,578	817,608
Source of Gas Purchased – Percent				
From California (California Producers)	**16.0%**	16.9%	16.5%	16.1%
From Other States (at California-Arizona Border)	**43.6**	36.9	34.9	36.2
From Canada (at U.S.-Canada Border)	**40.4**	46.2	48.6	47.7
Total	**100.0%**	100.0%	100.0%	100.0%
Average Cost of Gas Purchased – MCF (U.S. Operations)				
From California (California Producers)	**215.9¢**	173.6¢	159.4¢	112.1¢
From Other States (at California-Arizona Border)	**230.0**	179.1	135.1	110.0
From Canada (at U.S.-Canada Border)	**434.7**	260.8	222.2	200.2
Average	**310.4¢**	216.0¢	181.4¢	153.3¢
Peak Day Sendout – MCF	**3,275,016**	3,398,281	3,243,552	3,186,229
Average Annual Residential Consumption – MCF	**81.6**	90.4	86.9	90.5
Total Customers (end of year)	**2,858,129**	2,805,471	2,738,767	2,674,890
Customers Per Mile of Distribution Main	**97.0**	97.2	97.4	97.2

1976	1975	1974	1973	1972	1971	1970
$ 2.89	$ 2.64	$ 3.24	$ 3.21	$ 3.01	$ 2.75	$ 2.47
$ 1.88	$ 1.88	$ 1.88	$ 1.78	$ 1.72	$ 1.64	$ 1.50
64.9%	71.1%	58.0%	55.4%	57.2%	59.7%	60.9%
$28.10	$27.65	$28.14	$27.78	$26.35	$24.91	$23.66
24⅛	23½	24⅞	32⅝	33⅜	36⅜	35
20	18⅛	17	21½	26⅜	28⅜	22½
23⅛	20¾	20⅛	22⅞	32⅝	32⅜	34⅝
$518,398	$540,790	$536,931	$465,422	$458,817	$379,198	$330,559
131,864	99,230	124,857	113,377	92,076	84,444	106,845
$650,262	$640,020	$661,788	$578,799	$550,893	$463,642	$437,404
66,416	63,078	60,932	60,572	59,124	54,665	51,277
12.2%	22.7%	25.6%	21.5%	19.8%	25.6%	26.9%
62.0	43.9	38.1	53.4	52.7	46.5	48.6
25.8	33.4	36.3	25.1	27.5	27.9	24.5
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
2,419,900	2,396,900	2,396,900	2,384,800	2,369,800	2,364,900	2,364,900
8,261,000	8,053,000	7,947,000	7,841,000	7,062,000	6,956,000	6,942,400
3,743,400	3,766,100	2,948,700	2,554,700	2,609,900	2,438,700	2,098,000
14,424,300	14,216,000	13,292,600	12,780,500	12,041,700	11,759,600	11,405,300
12,245,800	11,632,800	11,648,800	10,867,800	10,469,800	9,713,000	8,807,700
6,509	6,462	6,260	6,417	6,213	6,048	5,697
3,087,300	3,005,518	2,936,106	2,854,585	2,767,978	2,675,942	2,597,314
37.7	37.2	36.9	36.5	36.0	35.4	34.8
852,935	876,721	888,193	997,912	1,031,355	1,017,045	959,669
16.5%	15.9%	16.5%	23.3%	23.1%	24.5%	25.0%
37.5	40.7	43.2	37.9	39.7	40.7	43.3
46.0	43.4	40.3	38.8	37.2	34.8	31.7
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
96.1¢	56.7¢	42.7¢	37.0¢	33.7¢	31.7¢	30.2¢
83.0	72.7	55.8	43.0	39.4	37.5	33.9
175.4	123.5	55.3	35.7	28.8	25.5	23.8
127.6¢	92.2¢	53.4¢	38.8¢	34.1¢	35.7¢	29.7¢
3,348,909	3,352,881	3,020,215	3,423,896	3,918,844	3,798,462	3,633,341
100.8	111.1	104.5	113.4	115.7	121.7	107.7
2,611,551	2,555,216	2,503,203	2,443,889	2,383,609	2,317,686	2,258,285
96.8	96.4	96.1	95.9	95.6	95.0	94.1

CONSOLIDATED REVENUES AND SALES

	In Thousands		
For the Years Ended December 31,	**1980**	1979	1978
Electric Department			
Revenues			
Residential	**$ 998,130**	$ 693,368	$ 720,112
Commercial	**1,067,197**	752,359	852,265
Industrial (1000 Kw demand or over)	**699,074**	461,653	531,593
Agricultural Power	**212,770**	142,727	149,986
Public Street and Highway Lighting	**38,225**	30,491	34,179
Other Electric Utilities	**71,926**	67,740	69,855
Miscellaneous	**58,568**	50,111	43,584
Other	**5,336**	4,115	3,814
Regulatory Balancing Account Changes	**(223,385)**	261,281	(308,455)
Total	**$ 2,927,841**	$ 2,463,845	$ 2,096,933
Sales – KWH			
Residential	**19,329,190**	19,605,541	18,314,721
Commercial	**18,283,154**	17,891,820	17,166,973
Industrial (1000 Kw demand or over)	**14,801,260**	15,253,371	14,815,289
Agricultural Power	**3,540,022**	3,715,026	3,120,644
Public Street and Highway Lighting	**431,564**	455,445	485,725
Other Electric Utilities	**1,906,465**	2,807,249	2,232,563
Total Sales to Customers	**58,291,655**	59,728,452	56,135,915
Gas Department			
Revenues			
Residential	**$ 799,307**	$ 555,017	$ 432,865
Commercial	**626,611**	406,497	346,229
Industrial	**708,259**	499,242	340,546
Other Gas Utilities	**148,074**	85,867	18,384
Miscellaneous	**(6,560)**	7,128	4,315
Regulatory Balancing Account Changes	**(133,807)**	176,354	193,960
Subsidiary Companies (U.S. and Canada)	**189,174**	170,519	136,141
Total	**$ 2,331,058**	$ 1,900,624	$ 1,472,440
Sales – MCF			
Residential	**216,184**	234,295	220,076
Commercial	**146,827**	143,707	144,162
Industrial	**161,060**	186,165	138,975
Other Gas Utilities	**34,821**	36,013	9,926
Total Sales to Customers	**558,892**	600,180	513,139
Company Use (electric generation)	**202,964**	216,062	125,636
By Subsidiary Companies (in U.S.)	**153**	130	120
Total	**762,009**	816,372	638,895

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

The following table displays data which is discussed under the captions in the text below.

Selected Financial Information — In Thousands (except percentage and per share information)

	1980		1979		1978		1977		1976	
Results of Operations:										
Rate of Return										
Earned	**8.6%**		8.5%		8.1%		8.3%		7.8%	
Authorized	**10.3%**		9.5%		9.5%		9.2%		9.2%	
Return on Equity										
Earned	**11.7%**		11.5%		10.9%		10.6%		10.1%	
Authorized	**14.1%**		12.8%		12.8%		12.8%		12.8%	
Earnings Per Common Share	**$3.60**		$3.55		$3.18		$3.14		$2.89	
Dividends Declared Per Common Share	**$2.60**		$2.38		$2.16		$2.00		$1.88	
Operating Revenues	**$ 5,258,899**		$ 4,364,469		$3,569,373		$3,629,530		$3,048,546	
Operating Income	**$ 573,147**		$ 515,903		$ 468,088		$ 459,432		$ 421,407	
Net Income	**$ 524,770**		$ 458,234		$ 400,451		$ 355,677		$ 301,465	
Liquidity:										
Construction Expenditures	**$ 1,221,758**		$ 1,149,308		$ 859,113		$ 721,324		$ 650,262	
Ratio of Construction Work in Progress to Net Utility Plant	**33.9%**		31.2%		27.3%		24.6%		21.9%	
Net Short-term Borrowings	**$ 671,313**		$ 574,775		$ 69,141		$ 121,724		$ 282,505	
Net Short-term Borrowings as a Percent of Total Capitalization	**7.3%**		6.9%		0.9%		1.7%		4.3%	
Capital Resources:										
Total Assets at Year End	**$11,295,203**		$10,310,763		$8,665,160		$8,216,285		$7,627,834	
Capitalization at Year End										
Common Stock Equity	**$ 3,726,870**	**40.5%**	$ 3,389,256	40.7%	$2,995,433	39.6%	$2,825,650	39.5%	$2,490,367	37.6%
Preferred Stock Without Mandatory Redemption Provision	**1,227,451**	**13.4**	1,102,451	13.2	1,102,451	14.6	977,451	13.7	877,451	13.2
Preferred Stock With Mandatory Redemption Provision	**150,000**	**1.6**	150,000	1.8	—	—	—	—	—	—
Long-term Debt	**4,087,080**	**44.5**	3,687,562	44.3	3,457,632	45.8	3,351,680	46.8	3,264,421	49.2
Total Capitalization	**$ 9,191,401**	**100%**	$ 8,329,269	100%	$7,555,516	100%	$7,154,781	100%	$6,632,239	100%
Depreciation Expense	**$ 280,710**		$ 250,864		$ 230,617		$ 218,209		$ 208,660	
Financing — Net Proceeds										
Long-term Debt	**$ 497,834**		$ 372,404		$ 249,567		$ 198,393		$ 172,804	
Preferred Stock	**132,306**		149,383		132,429		106,223		105,894	
Common Stock	**236,746**		276,564		58,758		225,638		187,770	
Total Financing	**$ 866,886**		$ 798,351		$ 440,754		$ 530,254		$ 466,468	

Results of Operation

In recent years the Company has fallen far short of earning its allowed rate of return principally because of inflation's tremendous impact on the Company. It increased the cost of extending service to new customers and the cost of providing that service. Some of the effects of inflation have been lessened by actions of the California Public Utilities Commission (CPUC) in their adoption of energy related balancing accounts, forward looking test years, more timely action on general rate increases and increases in allowed rates of return.

A series of balancing accounts have been established with a view to insuring ultimate recovery of major changes in fuel costs as well as reducing the exposure of the Company's earnings to fluctuations in gas sales. The first balancing account was the Energy Cost Adjustment Clause (ECAC), adopted April 1976, which permits the recovery of the cost of fuel used for electric generation and purchases of electricity from other producers. As part of this procedure, any difference between actual energy costs and actual ECAC revenues is accumulated in a balancing account.

This amount, with interest, is recovered from or refunded to customers through periodic rate adjustments. The allowed interest rate on balancing accounts has, since January 1, 1980, been the current commercial paper rate. Prior to that date recovery was limited to a fixed 7% rate.

Similar balancing accounts have since been established to permit recovery of the cost of gas and to permit recovery of the impact of gas sales fluctuations. The overall impact on the Company is that earnings are not affected by variations in those costs and revenues which are subject to balancing account procedures provided they are ultimately authorized to be recovered by the CPUC.

A plan was adopted by the CPUC in 1977 to reduce regulatory lag by processing general rate cases (which address all costs other than those handled through balancing accounts) within twelve months of the filing of an application. This plan is designed to allow major energy utilities in California the opportunity to receive general rate relief every other year at the beginning of a future test year.

The combined effect of these changes in regulation in California has been to insulate the Company's operating income and net income to an increasing extent from changes in the cost of electric energy, the cost of gas sold, and gas usage and from delays in general rate proceedings. The following table shows the major categories of changes in revenues from the preceding year. Rate changes include rate increases which occurred during the year at various times. The decline in volumes resulted principally from conservation due to PG&E sponsored awareness programs, CPUC mandated programs, price increases, and lower economic growth.

	In Millions				
Year Ended December 31,	**1980**	1979	1978	1977	1976
Electric Revenues					
Rate Changes					
General	**$ 88.2**	$ 4.2	$ 67.0	$ 88.7	$ 146.8
Energy	**891.5**	(354.4)	21.8	630.7	52.3
Sales Volume and Other Changes	**(31.0)**	147.4	(28.6)	53.9	79.2
Balancing Account Increases		569.7			249.1
Balancing Account Decreases	**(484.7)**		(318.4)	(239.1)	
Net Increase	**$ 464.0**	$ 366.9	$(258.2)	$ 534.2	$ 527.4
Gas Revenues					
Rate Changes					
General	**$ 68.0**	$ 106.2	$ 22.8	$ 28.8	$ 49.7
Gas Purchased	**767.9**	183.0	54.6	138.6	166.9
Sales Volume and Other Changes	**(95.3)**	156.6	(92.8)	(65.5)	(71.5)
Balancing Account Increases			213.4		35.6
Balancing Account Decreases	**(310.2)**	(17.6)		(55.1)	
Net Increase	**$ 430.4**	$ 428.2	$ 198.0	$ 46.8	$ 180.7

( ) Denotes decrease

The operation of the balancing accounts enables the Company to recover all fuel related costs as well as reductions in gas usage. However, the 1980 actual costs of labor and materials and financing costs such as interest and preferred stock dividends far exceeded the estimated allowance for such costs in the 1980 general rate case. To correct this deficiency the Company filed in 1980 for interim rate relief and received an increase of $155,000,000 in February 1981. This increase reduces by that amount the size of the previously filed general rate increase of $1,455,000,000 to become effective in 1982. This rate case is designed to substantially improve cash flow. If the CPUC decision is responsive, it should arrest the trend of the declining internal generation of funds.

Liquidity
Allowance for equity funds used during construction and allowance for borrowed funds used during construction has increased greatly in recent years as the result of higher costs of funds and the increasing investment in construction work in progress (CWIP). Annual rates of allowance for equity funds used during construction were 7.0% in 1980, 6.5% in 1979, and 6.4% in 1978. Annual rates of allowance for borrowed funds used during construction (net of the related income tax effect) were 1.7% in 1980, 1.6% in 1979 and 1.5% in 1978.

The ratio of CWIP to total net utility plant is an important indicator of the Company's ability to meet its capital requirements. Although allowance for equity and borrowed funds used during construction (AFUDC) is included in net income, this return is not current cash income. Only when construction is included in utility rate base does it begin to contribute to the Company's cash flow. On the other hand, construction expenditures do require current cash expenditures, both for the construction itself and for the interest and dividends required on the investment in CWIP. As the ratio of construction work in progress to total net utility plant grows larger, it becomes more difficult to generate the cash needed for additional construction.

Two large construction projects contribute heavily to the large amounts of AFUDC—Diablo Canyon nuclear generating station and Helms pumped storage project. At year end the two nuclear units were substantially complete and were awaiting operating licenses. Total investment in the two units at December 31, 1980 was $1,789,000,000 including $647,000,000 of AFUDC. The Helms pumped storage project is well over half completed and at December 31, 1980 had accumulated costs of $438,000,000 including $57,000,000 of AFUDC. Because of the large size of the Diablo nuclear unit and Helms pumped storage project investments still under construction, the large amount of CWIP relative to net utility plant is a matter of serious concern to the Company. The CPUC has indicated that it intends to treat large projects such as the Diablo nuclear units and Helms pumped storage as special offset rate cases when they become operational. Under this procedure the Company expects that general rates will be increased to cover the cost of depreciation, return on investment and operating expense while energy rates will be reduced because of the lower costs of power from nuclear and pumped storage units. Since AFUDC for these projects will be discontinued, there should be little, if any, effect on the Company's earnings, but cash flow will be greatly improved and the ratio of CWIP to total net utility plant will be greatly reduced.

One of the major financial trends in the last five years has been the increase in the use of various forms of short-term debt relative to capitalization. The reason for this increase was a change in policy to use short-term debt (primarily commercial paper) to finance the unrecovered balances in balancing accounts and fuel inventory increases during this period. The Company has a policy of maintaining bank lines of credit to support all sales of commercial paper.

Capital Resources
The Company continues to extend and enlarge its facilities to ensure reliable service in its service territory to all who want it. It is anticipated that consolidated construction expenditures during 1981 will approximate $1,394,000,000, of which amount $1,031,000,000 will be attributable to electric facilities and $363,000,000 to gas facilities. The Company has raised capital and issued debt securities, preferred stock and common stock in such proportions that at year-end 1980 capitalization ratios were 45%, 15% and 40%, respectively.

Because of the regulatory considerations, inflation, and the greater difficulty of obtaining new sources of energy, the costs of replacing and adding to the Company's energy supplies have increased greatly. The actual costs are larger and projects are under construction for longer periods than in the past. This situation increases the risk the Company may have of not recovering its entire investment in projects not carried to a successful conclusion. The CPUC as a matter of policy has in the past disallowed recovery of allowance for equity and borrowed funds used during construction on unsuccessful projects of other utilities in the state, although it has consistently allowed utilities under its jurisdiction to amortize the costs other than AFUDC of abandoned projects and has established rates to cover that amortization. There is no reasonable way to estimate which projects, if any, may be abandoned and therefore the aggregate amount of possible loss of AFUDC if the CPUC adheres to its past policy. The Company intends to pursue vigorously any avenue available to it if any of its projects must be abandoned and legitimate costs such as AFUDC become a burden of the equity holder.

The favorable resolution of the items discussed above will aid the Company in the achievement of its financial objectives. Among these objectives are the maintenance of its long-term debt rating at AA, its preferred stock rating at A, its short-term debt rating at A-1/P-1, and the sale of its common stock at book value or above. Of these objectives, holding the selling price of the Company's common stock at book value or above has not been realized in recent years.

OPINION OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

The Stockholders and the Board of Directors of Pacific Gas and Electric Company

We have examined the consolidated balance sheets of Pacific Gas and Electric Company and its subsidiaries as of December 31, 1980 and 1979 and the related consolidated statements of income, funds used for construction, and common stock equity and preferred stock for each of the three years in the period ended December 31, 1980. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, such consolidated financial statements present fairly the financial position of the Company and its subsidiaries at December 31, 1980 and 1979 and the results of their operations and funds used for construction for each of the three years in the period ended December 31, 1980, in conformity with generally accepted accounting principles applied on a consistent basis.

Deloitte Haskins & Sells

San Francisco, California
February 17, 1981

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	1980	1979	1978
	In Thousands (Except per share amounts)		
Operating Revenues			
Electric	**$2,927,841**	$2,463,845	$2,096,933
Gas	**2,331,058**	1,900,624	1,472,440
Total Operating Revenues	**5,258,899**	4,364,469	3,569,373
Operating Expenses			
Operation			
Cost of Electric Energy	**1,465,680**	1,231,169	912,873
Cost of Gas Sold	**1,833,831**	1,405,516	1,045,978
Transmission	**105,594**	102,999	91,346
Distribution	**122,720**	110,227	97,610
Customer Accounts and Services	**150,282**	122,413	101,284
Administrative and General	**275,714**	226,016	184,975
Other	**63,426**	49,161	38,295
Total Operation	**4,017,247**	3,247,501	2,472,361
Maintenance	**157,262**	132,577	124,378
Depreciation	**280,710**	250,864	230,617
Gas Exploration	**13,213**	13,050	4,631
Taxes on Income	**123,698**	100,071	133,264
Property and Other Taxes	**93,622**	104,503	136,034
Total Operating Expenses	**4,685,752**	3,848,566	3,101,285
Operating Income	**573,147**	515,903	468,088
Other Income and Income Deductions			
Allowance for Equity Funds Used During Construction	**202,873**	159,669	125,625
Interest Income	**96,442**	36,016	22,736
Minority Interest in Net Income of Subsidiary Companies	**(4,991)**	(3,934)	(2,790)
Other – Net	**41,422**	21,500	23,265
Total Other Income and Income Deductions	**335,746**	213,251	168,836
Income Before Interest Charges	**908,893**	729,154	636,924
Interest Charges			
Interest on Long-term Debt	**322,344**	279,912	255,296
Interest on Short-term Debt	**112,609**	26,137	11,201
Less Allowance for Borrowed Funds Used During Construction	**(50,830)**	(35,129)	(30,024)
Total Interest Charges	**384,123**	270,920	236,473
Net Income	**524,770**	458,234	400,451
Preferred Dividend Requirements	**109,169**	92,291	83,337
Earnings Available for Common	**$ 415,601**	$ 365,943	$ 317,114
Average Common Shares Outstanding	**115,600**	103,225	99,580
Earnings Per Common Share	**$3.60**	$3.55	$3.18
Dividends Declared Per Common Share	**$2.60**	$2.38	$2.16

The accompanying notes to consolidated financial statements are an integral part of these statements.

CONSOLIDATED BALANCE SHEETS

	In Thousands	
December 31,	**1980**	1979
Assets		
Utility Plant (at original cost)		
Electric	**$ 6,804,267**	$ 6,346,657
Gas	**2,219,386**	2,112,778
Construction Work in Progress	**3,078,485**	2,565,813
Total Utility Plant	**12,102,138**	11,025,248
Accumulated Depreciation	**3,031,467**	2,793,716
Utility Plant — Net	**9,070,671**	8,231,532
Gas Exploration Costs	**132,094**	83,106
Advances to Gas Producers	**144,190**	103,493
Investment in LNG Partnerships	**145,559**	117,459
Investment in Alaska Natural Gas Transportation System	**33,383**	23,718
Investment in Alberta Natural Gas Company Ltd	**21,409**	18,552
Other Investments	**2,277**	4,522
Current Assets		
Cash	**1,715**	2,888
Short-term Investments (at cost which approximates market)	**66,242**	120,856
Accounts Receivable		
Customers	**489,885**	347,257
Other	**79,185**	62,724
Total Accounts Receivable	**569,070**	409,981
Less Allowance for Uncollectible Accounts	**5,872**	6,122
Accounts Receivable — Net	**563,198**	403,859
Regulatory Balancing Accounts — Receivable	**325,360**	622,142
Inventories (at average cost)		
Fuel Oil	**453,885**	207,317
Gas Stored Underground	**202,887**	166,552
Materials and Supplies	**96,902**	71,188
Total Inventories	**753,674**	445,057
Federal Income Tax Refund	**—**	76,000
Prepayments	**12,022**	15,544
Total Current Assets	**1,722,211**	1,686,346
Deferred Charges		
Unamortized Bond Expense	**4,929**	6,218
Other — Net	**18,480**	35,817
Total Deferred Charges	**23,409**	42,035
Total Assets	**$11,295,203**	$10,310,763

The accompanying notes to consolidated financial statements are an integral part of these statements.

December 31,	1980	1979
	In Thousands	
Capitalization and Liabilities		
Capitalization		
Common Stock (shares outstanding at December 31, 1980 and December 31, 1979 were 123,849,412 and 113,627,542, respectively)	**$ 1,238,494**	$ 1,136,275
Additional Paid-in Capital	**931,526**	812,802
Reinvested Earnings	**1,556,850**	1,440,179
Common Stock Equity	**3,726,870**	3,389,256
Preferred Stock Without Mandatory Redemption Provision	**1,227,451**	1,102,451
Preferred Stock With Mandatory Redemption Provision	**150,000**	150,000
Long-term Debt	**4,087,080**	3,687,562
Total Capitalization	**9,191,401**	8,329,269
Current Liabilities		
Short-term Borrowings	**737,555**	695,631
Accounts Payable — trade creditors	**452,711**	371,679
Accounts Payable — other	**59,240**	68,530
Accrued Taxes	**244,935**	221,563
Interest Payable	**29,820**	25,270
Dividends Payable	**76,448**	69,273
Customer Deposits	**15,568**	14,827
Long-term Debt — current portion	**10,364**	52,015
Refunds Due Customers	**25,889**	71,939
Other	**62,391**	45,316
Total Current Liabilities	**1,714,921**	1,636,043
Deferred Credits		
Customer Advances for Construction	**90,667**	84,189
Deferred Investment Tax Credits	**36,187**	76,201
Deferred Income Taxes of Subsidiaries	**49,007**	28,944
Deferred Income Taxes on Defense Facilities	**25,703**	28,647
Unamortized Gain on Reacquired Debt	**88,743**	58,366
Other	**36,476**	27,784
Total Deferred Credits	**326,783**	304,131
Minority Interest in Subsidiary Companies	**62,098**	41,320
Commitments and Contingencies (Note 7)	—	—
Total Capitalization and Liabilities	**$11,295,203**	$10,310,763

CONSOLIDATED STATEMENTS OF FUNDS USED FOR CONSTRUCTION

	In Thousands		
For the Years Ended December 31,	**1980**	1979*	1978*
Funds Internally Generated			
Net Income	**$ 524,770**	$ 458,234	$400,451
Nonfund Items in Net Income			
Depreciation (including charges to other accounts)	**284,634**	254,068	234,049
Allowance for Equity Funds Used During Construction	**(202,873)**	(159,669)	(125,625)
Other—Net	**8,354**	23,570	3,511
Funds from Operations	**614,885**	576,203	512,386
Regulatory Balancing Accounts	**296,782**	(523,602)	122,256
Dividends on Preferred and Common Stock	**(408,099)**	(340,358)	(296,856)
Funds Internally Generated	**503,568**	**(287,757)**	**337,786**
Funds From Financing			
Common Stock Sold	**209,296**	276,564	58,758
Common Stock Sold by Subsidiary Company	**27,450**	—	—
Preferred Stock Sold	**132,306**	149,383	132,429
Long-term Debt Sold	**497,834**	372,404	249,567
Funds From Financing	**866,886**	**798,351**	**440,754**
Total Funds	**1,370,454**	**510,594**	**778,540**
Other Sources (Uses) of Funds			
Long-term Debt Matured	**(51,482)**	(100,628)	(74,117)
Long-term Debt Purchased for Sinking Fund (at cost)	**(51,997)**	(43,680)	(35,108)
Fuel Oil Inventory	**(246,568)**	(52,912)	94,556
Gas Stored Underground	**(36,335)**	(4,462)	(53,384)
Net Short-term Borrowings	**96,538**	505,634	(46,192)
Accounts Receivable	**(159,339)**	31,869	(54,878)
Other Changes in Working Capital	**91,935**	115,399	112,844
Other—Net	**5,679**	27,825	11,227
Total Other Sources	**(351,569)**	**479,045**	**(45,052)**
Total Funds Used for Construction	**1,018,885**	**989,639**	**733,488**
Allowance for Equity Funds Used During Construction	**202,873**	159,669	125,625
Total Construction Expenditures	**$1,221,758**	**$1,149,308**	**$859,113**

*Changed to conform to the 1980 format.

The accompanying notes to consolidated financial statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF COMMON STOCK EQUITY AND PREFERRED STOCK

	In Thousands					
For the Years Ended December 31, 1980, 1979, and 1978	Common Stock	Additional Paid-in Capital	Reinvested Earnings	Common Stock Equity	Preferred Stock Without Mandatory Redemption Provision	Preferred Stock With Mandatory Redemption Provision
Balance, January 1, 1978	$ 983,901	$623,042	$1,218,708	$2,825,651	$ 977,451	$ —
Net Income – for year			400,451	400,451		
Preferred Stock Sold (5,000,000 Shares)		7,429		7,429	125,000	
Common Stock Sold (2,489,160 Shares)	24,892	33,866		58,758		
Cash Dividends Declared						
Preferred Stock			(81,196)	(81,196)		
Common Stock			(215,660)	(215,660)		
Balance, December 31, 1978	1,008,793	664,337	1,322,303	2,995,433	1,102,451	—
Net Income – for year			458,234	458,234		
Preferred Stock Sold (1,500,000 Shares)		(617)		(617)		150,000
Common Stock Sold (12,748,253 Shares)	127,482	149,082		276,564		
Cash Dividends Declared						
Preferred Stock			(90,041)	(90,041)		
Common Stock			(250,317)	(250,317)		
Balance, December 31, 1979	1,136,275	812,802	1,440,179	3,389,256	1,102,451	150,000
Net Income – for year			**524,770**	**524,770**		
Preferred Stock Sold (5,000,000 Shares)		**7,306**		**7,306**	**125,000**	
Common Stock Sold (10,221,870 Shares)	**102,219**	**107,077**		**209,296**		
Cash Dividends Declared						
Preferred Stock			**(106,502)**	**(106,502)**		
Common Stock			**(301,597)**	**(301,597)**		
Increase from Capital Transaction of Subsidiary Company		**4,341**		**4,341**		
Balance, December 31, 1980	**$1,238,494**	**$931,526**	**$1,556,850**	**$3,726,870**	**$1,227,451**	**$150,000**

The accompanying notes to consolidated financial statements are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the Years Ended December 31, 1980, 1979 and 1978

Note 1
Summary of Significant Accounting Policies

Accounting Records
The accounting records of Pacific Gas and Electric Company (PG&E) are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the California Public Utilities Commission (CPUC).

Principles of Consolidation
The consolidated financial statements include the accounts of PG&E and its wholly owned and majority owned subsidiaries for all periods presented. In consolidation all significant intercompany transactions and accounts have been eliminated.

PG&E's major subsidiaries are Pacific Gas Transmission Company (PGT), which transports and sells natural gas outside California; Alberta and Southern Gas Co. Ltd. (A&S), whose principal functions are the acquisition of gas in Canada and arranging for its transportation to the U.S. border; and Natural Gas Corporation of California (NGC), which is a natural gas exploration and producing company. Subsidiaries of PG&E engaged in projects that are still in the development stages include four subsidiaries formed to engage in the delivery of liquified natural gas by ship to California; Eureka Energy Company, primarily a coal-owning and producing company; and Calaska Energy Company, a member of the partnership to construct the Alaskan portion of the Alaska Natural Gas Transportation System for the transportation of natural gas from Alaska to the continental United States. The investment in Alberta Natural Gas Company Ltd (a 45% owned subsidiary of Pacific Gas Transmission Company), whose principal function is to transport gas for A&S to the Canadian-U.S. border, is accounted for in accordance with the equity method of accounting.

The financial statements of Alberta and Southern Gas Co. Ltd. and the equity in Alberta Natural Gas Company Ltd are translated from Canadian dollars into United States dollars in accordance with pronouncements of the Financial Accounting Standards Board.

Revenues
Revenues consist of billings to customers and changes in balancing accounts. Billings to customers are included in revenues as meters are read on a cycle basis throughout each month. In accordance with orders of the CPUC, the Company has established balancing accounts for electric energy costs, gas costs and gas sales. Operating revenues include changes in these balancing accounts. These changes represent amounts authorized by the CPUC to be recovered from or refunded to customers. The effect of using these balancing accounts is that changes in costs to the Company of electric energy and gas, and fluctuations in gas sales do not affect the Company's earnings.

Utility Plant
The cost of additions to utility plant and replacements of retirement units of property is capitalized. Cost includes labor, material and similar items and indirect charges for such items as engineering, supervision and transportation. Cost also includes allowance for funds used during construction, at rates calculated in conformity with FERC regulations, for the imputed cost of equity investment and a net after-tax amount for borrowed funds. The equity component of allowance for funds used during construction is included in other income and the borrowed funds component ,net of federal and state income taxes, is recorded as a reduction of interest charges. Costs of depreciable units of plant retired are eliminated from utility plant accounts and such costs plus removal expenses less salvage are charged to accumulated depreciation. Costs of repairing property and replacement of minor items of property are included in the Consolidated Statements of Income as maintenance.

Depreciation
For financial statement purposes, depreciation of utility plant is computed on a straight-line remaining life basis at rates based on the estimated useful lives of properties. The annual provisions for depreciation expressed as a percentage of the average balances of depreciable plant were 3.4% for 1980 and 3.1% for 1979 and 1978. For federal income tax purposes, depreciation is generally computed using the most liberalized methods allowed by the Internal Revenue Code.

Income Taxes
The CPUC requires that deferred taxes not be provided on certain timing differences in connection with depreciation and overhead costs of construction. The CPUC also requires that investment tax credits be applied as a reduction of federal income tax through the use of a two-year moving average method in 1980 and a five-year moving average method in 1978-1979. Customer rates authorized by the CPUC reflect these requirements. Deferred taxes are provided primarily on changes in regulatory balancing accounts and gas exploration costs.

Bond Premium, Discount and Related Expenses
Bond issuance premium or discount and related expenses are amortized over the lives of the issues to which they pertain. The gain or loss on reacquisition of bonds to satisfy sinking fund requirements is amortized over the remaining life of the reacquired issues. The federal income tax on such gain is recognized over the life of the remaining property.

Earnings Per Common Share
Earnings per common share are computed by dividing earnings available for common stock by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding is computed by dividing the aggregate of the number of common shares outstanding at the beginning of each month in the period by the number of months in the period.

Research and Development
Research and development (R&D) costs related to specific construction projects and a portion of general engineering research costs are capitalized. Total research and development costs incurred during the years 1980, 1979 and 1978 were approximately $79,000,000, $76,000,000 and $60,000,000 respectively, of which $61,000,000, $60,000,000, and $47,000,000 were capitalized as part of the cost of construction projects. Other R&D costs are charged to expense as incurred.

Gas Exploration Costs
Gas exploration costs are capitalized under a modified "full cost" method of accounting as authorized by the CPUC. Unsuccessful project costs, current operating costs and the financing costs of the gas exploration program are recovered through gas exploration development balancing account procedures. The success, or lack of success of the Company's gas exploration program does not affect the Company's income because of the operation of the Gas Exploration and Development balancing account.

Note 2
Common Stock
Common stock, par value $10 per share, authorized 200,000,000 shares, outstanding at December 31, 1980 and December 31, 1979 were 123,849,412 and 113,627,542 respectively.

Note 3
Preferred Stock
The redeemable preferred stock ($25 par) outstanding, with no mandatory redemption provision, is subject to redemption, in whole or in part, solely at the option of the Company upon payment of the redemption price plus accumulated and unpaid dividends to the date fixed for redemption. The redemption premium per share declines in accordance with terms of the specific issue. The involuntary liquidation preference of the preferred stock is par value ($25) plus accrued dividends.

The redeemable preferred stock ($100 par) outstanding, with a mandatory redemption provision, is subject to redemption through the operation of a sinking fund at the sinking fund redemption price of $100 per share, or at the option of the Company upon payment of the redemption price of $100 per share plus a premium, plus in either event accumulated and unpaid dividends to the date fixed for redemption. The redemption premium per share declines annually. For the purposes of the sinking fund the Company must set aside in cash, annually, commencing with

November 15, 1985, and ending on November 15, 2004, an amount sufficient to redeem 75,000 shares at the sinking fund redemption price. This provision is cumulative. There are no redemption requirements for the years 1981 through 1984. The Company has the right, at its option, to redeem at the sinking fund redemption price, on November 15, 1985 and on any November 15 thereafter, not more than 75,000 additional shares. This right is not cumulative. Optional redemptions at the sinking fund redemption price are limited to an aggregate of 562,000 shares. The involuntary liquidation preference of this stock is par value ($100) plus accrued dividends.

Dividends on preferred stock are cumulative. Total preferred stock outstanding at December 31, 1980 was:

	Dividend Per Share	Redemption Price Per Share	In Thousands Shares Authorized	Shares Issued and Outstanding Included Under "Capitalization" in Balance Sheet Number	Amount
Preferred Without Mandatory Redemption Provision Par Value $25 Per Share					
Non-Redeemable					
6%	$1.50		4,212	4,212	$105,292
5.50%	1.375		1,173	1,173	29,329
5%	1.25		400	400	10,000
Total Non-Redeemable			5,785	5,785	$144,621
Redeemable					
12.80%	$3.20	$30.70	5,000	5,000	$125,000
10.46%	2.615	30.10	3,500	3,500	87,500
10.28%	2.57	30.00	5,000	5,000	125,000
10.18%	2.545	30.00	4,000	4,000	100,000
9.48%	2.37	29.50	3,000	3,000	75,000
9.30%	2.325	29.80	4,000	4,000	100,000
9.28%	2.32	27.25	707	707	17,674
9%	2.25	29.25	881	881	22,027
8.20%	2.05	29.375	2,000	2,000	50,000
8.16%	2.04	28.875	3,000	3,000	75,000
8%	2.00	29.375	2,000	2,000	50,000
7.84%	1.96	29.00	2,000	2,000	50,000
5%	1.25	26.75	2,861	2,861	71,524
5%—Series A	1.25	26.75	1,750	1,719	42,985
4.80%	1.20	27.25	1,517	1,517	37,934
4.50%	1.125	26.00	1,128	1,128	28,186
4.36%	1.09	25.75	1,000	1,000	25,000
Unclassified in Series	—	—	25,871	—	—
Total Redeemable			69,215	43,313	$1,082,830
Total Preferred Stock Without Mandatory Redemption Provision			**75,000**	**49,098**	**$1,227,451**
Preferred With Mandatory Redemption Provision Par Value $100 Per Share					
Redeemable					
9%	$9.00	$100.00	1,500	1,500	$150,000
Unclassified in Series		—	8,500	—	—
Total Preferred Stock With Mandatory Redemption Provision			**10,000**	**1,500**	**$150,000**

Note 4
Long-term Debt

The First and Refunding Mortgage Bonds of PG&E are issued in series, bear annual interest from 2¾% to 12⅞% and mature from June 1, 1981 to August 1, 2013. Subject to indenture provisions as to earnings coverage and bondable property available for security, additional bonds may be issued up to an outstanding aggregate amount of $5,000,000,000. The Board of Directors of PG&E may from time to time increase the amount authorized. All real properties and substantially all personal properties are subject to the lien of the mortgage.

PG&E's securities representing investments in subsidiaries are pledged as collateral for PG&E bonds. The mortgage bonds of PGT are issued in series, bear annual interest from 5¼% to 8% and mature from 1986 to 1990. All real properties and substantially all personal properties and long-term contracts for gas purchases, gas sales and gas transportation of PGT are subject to the lien of the PGT mortgage.

At December 31, 1980, long-term debt of PG&E and subsidiaries was:

	In Thousands			
Maturity	2¾% to 3¾%	4¼% to 6⅞%	7½% to 12⅞%	Total
Pacific Gas and Electric Company				
Mortgage Bonds				
1981	$ 21,117	$ —	$ —	$ 21,117
1982	60,895	—	150,000	210,895
1983	55,288	—	16,700	71,988
1984	49,631	—	16,700	66,331
1985	18,083	—	200,350	218,433
1986-1995	21,005	223,293	87,500	331,798
1996-2005	—	430,590	1,112,434	1,543,024
2006-2013	—	2,870	1,594,750	1,597,620
Total Mortgage Bonds	$226,019	$656,753	$3,178,434	4,061,206
Current Portion Net of Reacquired Bonds Included in Current Liabilities				(6,457)
Unamortized Discount Net of Premium				(24,546)
PG&E Mortgage Bonds Included in Long-term Debt				4,030,203
Pacific Gas Transmission Company				
Mortgage Bonds 5¼% Series, due January 1986				21,092
Mortgage Bonds 8% Series, due November 1990 (Net of Bonds Held in Treasury)				18,316
Subordinated Debentures 5½%				408
Total Long-term Debt				39,816
Unamortized Discount, 8% Series				(53)
Current Portion Included in Current Liabilities				(3,907)
PGT Long-term Debt Included in Long-term Debt				35,856
Alberta and Southern Gas Co. Ltd.				
Bank Loans — Canadian prime rate plus ½%, due 1981				17,476
Eureka Energy Company				
Notes Payable — 10.5% Interest, due 1982-1996				3,545
Total Long-term Debt of PG&E and Subsidiaries				$4,087,080

PG&E is required, according to provisions of the First and Refunding Mortgage, to make semi-annual sinking fund payments on February 1 and August 1 of each year for the retirement of the bonds of PG&E equal to ½ of one percent of the aggregate bonded indebtedness outstanding on the preceding November 30 and May 31, respectively. Bonds of any series may be used to satisfy this requirement.

PGT's First Mortgage Pipeline Bonds and subordinated debentures, which are solely the obligation of PGT, are subject to redemption, at specified redemption prices, through the operation of a sinking fund or in larger increments at PGT's option, depending upon the series and redemption date. The debentures are subordinated in right of payment to mortgage debt and certain other indebtedness.

The Company's combined aggregate amount of bonds maturing and sinking fund requirements for the years 1981 through 1985, calculated on the basis of bonds outstanding at December 31, 1980, are $68,407,000, $257,306,000, $115,808,000, $109,056,000 and $260,181,000, respectively.

Note 5
Taxes on Income

Taxes on income generally reflect amounts currently payable with the exception of taxes related to changes in regulatory balancing accounts, investment tax credits, and subsidiaries' gas exploration costs. Changes in electric and gas balancing accounts are not included in federal and state income tax returns until such changes are billed to customers. The net unbilled amount included in the balancing accounts at December 31, 1980 was approximately $325,000,000 which will result in an additional tax payment of $166,000,000 when billed. This amount is included in Accrued Taxes. In addition, the Company has available investment tax credits of approximately $67,000,000 to reduce federal income tax payments for years after 1980.

The reasons for the differences between the reported income tax expense and the amount computed by applying the federal income tax rate of 46% for 1980 and 1979 and 48% for 1978 to income before taxes are:

	In Thousands		
	1980	1979	1978
Computed provision	**$274,674**	$250,943	$244,450
Increases (reductions) resulting from			
Investment tax credits	**(55,669)**	(37,920)	(29,709)
State tax on income	**14,225**	13,165	13,125
Allowance for equity and borrowed funds used during construction	**(116,703)**	(89,607)	(74,712)
Tax depreciation in excess of book depreciation	**(521)**	(10,836)	(20,692)
Other overhead construction costs	**(20,788)**	(18,167)	(17,328)
Repair allowance	**(11,500)**	(11,270)	(16,656)
Property taxes	**(5,486)**	(2,874)	15,028
Property removal expenses	**(5,520)**	(5,060)	(5,280)
Other – net	**(365)**	(1,081)	594
Total	**$ 72,347**	$ 87,293	$108,820

Income tax expense (credit) is included in the financial statements as follows:

	In Thousands		
	1980	1979	1978
Included in operating expenses	**$123,698**	$100,071	$133,264
Included in other income	**(51,351)**	(12,778)	(24,444)
Total	**$ 72,347**	$ 87,293	$108,820

The components of income tax expense (credit) are:

	In Thousands		
	1980	1979	1978
Current			
Federal	**$ 72,138**	$(76,000)	$108,951
State	**50,775**	—	41,249
Canadian	**1,454**	121	234
Deferred			
Tax related to changes in regulatory balancing accounts			
Federal	**(35,811)**	100,349	(40,207)
State	**(28,249)**	20,818	(15,773)
Investment tax credit			
Federal	**(5,078)**	24,265	17,348
Amortization of deferred taxes on defense facilities			
Federal	**(2,694)**	(2,694)	(2,694)
State	**(251)**	(251)	(251)
Other deferred			
Federal	**16,382**	16,303	(334)
State	**4,068**	3,812	130
Canadian	**(387)**	570	167
Total	**$ 72,347**	$ 87,293	$108,820

Note 6
Compensating Balances and Short-term Borrowing Arrangements

The Company maintains lines of credit with twenty-three banks, principally to support the sale of commercial paper. At December 31, 1980, these lines of credit totaled $608,925,000. At no time during the year were the lines of credit used for direct bank borrowings.

The Company also maintains a credit arrangement with five banks totaling $160,000,000 for the discounting of bankers acceptances which are used to pay for Canadian natural gas. The usual terms of bankers acceptances are for no more than 60 days and 10 to 90 days for commercial paper. Alberta & Southern also maintains a line of credit totaling $10,088,000 with four banks.

In addition to the above lines of credit, on December 17, 1980, PGT entered into a $160,000,000 financing agreement with nine banks for the Western Leg Prebuild of the Alaska Natural Gas Transportation System. This financing will be available either to support commercial paper sales or for direct borrowing until it converts to a seven-year term loan after the completion of construction. As of December 31, 1980, none of this line of credit was utilized.

The Company compensates banks for lines of credit and other banking services by fee payments or by maintaining cash balances. The cash balances maintained at the banks are not legally restricted.

Short-term borrowings and interest rates thereon were as follows:

	In Thousands (Except Percentages)		
For the Years Ended December 31,	**1980**	1979	1978
Balance of Short-term Borrowings Outstanding at End of Period			
Commercial Paper	**$591,955**	$677,882	$68,235
Bankers Acceptances	**$110,000**	—	—
Bank Loans	**$ 35,600**	$ 17,749	$ 1,404
Weighted Average Interest Rates for Short-term Borrowings Outstanding at End of Period			
Commercial Paper	**17.9%**	13.6%	10.2%
Bankers Acceptances	**16.1%**	—	—
Bank Loans	**14.1%**	15.5%	11.9%

On February 4, 1981, the Company entered into an agreement to sell and leaseback nuclear fuel for use at the Diablo Canyon Nuclear Power Plant with Pacific Energy Trust (Energy). On that date, the Company transferred to Energy its title and interest in the current nuclear fuel inventory, which at December 31, 1980 was $216,900,000 included in Construction Work in Progress. When the nuclear fuel is generating heat, the Company will make quarterly payments to Energy for the cost of fuel consumed which will include costs arising out of the ownership of the nuclear fuel. The Company also has a provision with Energy to borrow at any time an amount equal to the difference between $300,000,000 and Energy's investment in nuclear fuel up to a maximum of $120,000,000 (in addition to all the above mentioned lines of credit).

Note 7
Commitments and Contingencies

Construction expenditures for the year 1981 are estimated to be $1,394,000,000.

The Company is a member of Nuclear Mutual Limited (NML), established by the utility industry to provide insurance coverage against property damage to members' nuclear generating facilities whether under construction or in operation. In the event of property damage to a nuclear plant of a member utility, the Company may be subject to a maximum assessment of approximately $21,000,000 if losses exceed premiums, reserves and other NML resources.

The Company advised the Nuclear Regulatory Commission's Atomic Safety and Licensing Board that a final decision to restart the nuclear power plant unit at Humboldt Bay will be deferred until retrofit requirements are defined. The net investment in the power plant is approximately $52,000,000. If a decision is made not to restart the nuclear unit, substantially all costs are expected to be recovered through future regulatory proceedings.

See the Capital Resources section of Management's Discussion and Analysis of Consolidated Financial Condition and Results of Operation for information relating to the policy of the CPUC regarding recovery of costs of unsuccessful projects.

The Company is required to make advance payments to gas producers if it does not take the contractual minimum annual volume of natural gas during a contract year. Unless export licenses from Canada are extended, or large sales agreements are entered into, or the Company is successful in negotiating the reduction in the required minimums, the Company may not have the opportunity to fully recover the volume of natural gas not taken under these contracts.

The Company has entered into various arrangements to lease automotive equipment, computer equipment, office equipment and other incidental equipment and property which are accounted for as operating leases in accordance with CPUC ratemaking practices. The annual lease expenses are not material.

Note 8
Segment Information

For the Years Ended December 31,	Electric	Gas	Intersegment Eliminations	Total
	In Thousands			
1980				
Operating Revenues	**$2,927,841**	**$2,331,058**		**$ 5,258,899**
Intersegment Sales(1)	**4,549**	**812,833**	**$(817,382)**	**—**
Total Operating Revenues	**2,932,390**	**3,143,891**	**(817,382)**	**5,258,899**
Depreciation	**204,878**	**75,832**	**—**	**280,710**
Taxes on Income(2)	**65,803**	**57,895**	**—**	**123,698**
Other Operating Expenses(2)	**2,256,563**	**2,842,163**	**(817,382)**	**4,281,344**
Total Operating Expenses	**2,527,244**	**2,975,890**	**(817,382)**	**4,685,752**
Operating Income	**$ 405,146**	**$ 168,001**	**$ —**	**$ 573,147**
Construction Expenditures(3)	**$ 973,785**	**$ 247,973**		**$ 1,221,758**
Utility Assets(3)	**$5,615,192**	**$2,601,526**		**$ 8,216,718**
Construction Work in Progress(3)	**2,985,187**	**93,298**		**3,078,485**
Total Assets	**$8,600,379**	**$2,694,824**		**$11,295,203**
1979				
Operating Revenues	$2,463,845	$1,900,624		$ 4,364,469
Intersegment Sales(1)	3,440	556,354	$(559,794)	—
Total Operating Revenues	2,467,285	2,456,978	(559,794)	4,364,469
Depreciation	183,995	66,869	—	250,864
Taxes on Income(2)	63,168	36,903	—	100,071
Other Operating Expenses(2)	1,834,935	2,222,490	(559,794)	3,497,631
Total Operating Expenses	2,082,098	2,326,262	(559,794)	3,848,566
Operating Income	$ 385,187	$ 130,716	$ —	$ 515,903
Construction Expenditures(3)	$ 943,911	$ 205,397		$ 1,149,308
Utility Assets(3)	$5,257,874	$2,487,076		$ 7,744,950
Construction Work in Progress(3)	2,521,809	44,004		2,565,813
Total Assets	$7,779,683	$2,531,080		$10,310,763
1978				
Operating Revenues	$2,096,933	$1,472,440		$ 3,569,373
Intersegment Sales(1)	3,774	305,088	$(308,862)	—
Total Operating Revenues	2,100,707	1,777,528	(308,862)	3,569,373
Depreciation	167,014	63,603	—	230,617
Taxes on Income(2)	104,346	28,918	—	133,264
Other Operating Expenses(2)	1,461,448	1,584,818	(308,862)	2,737,404
Total Operating Expenses	1,732,808	1,677,339	(308,862)	3,101,285
Operating Income	$ 367,899	$ 100,189	$ —	$ 468,088
Construction Expenditures(3)	$ 718,572	$ 140,541		$ 859,113
Utility Assets(3)	$4,605,656	$2,025,286		$ 6,630,942
Construction Work in Progress(3)	2,008,144	26,074		2,034,218
Total Assets	$6,613,800	$2,051,360		$ 8,665,160

(1) Intersegment sales for 1980, 1979 and 1978 represent 26%, 23% and 17%, respectively, of Total Gas Revenues and less than 1% of Total Electric Revenues. Intersegment Electric and Gas Sales are accounted for at tariff rates prescribed by the CPUC.

(2) Taxes on Income and general corporate expenses are allocated to departments in accordance with the Uniform System of Accounts and requirements of the CPUC.

(3) Includes allocation of Common Utility Plant.

Note 9
Retirement Plan
The Company provides retirement plans covering substantially all employees. The cost of these plans charged to expense and utility plant for 1980, 1979 and 1978 was $75,000,000, $69,000,000, and $63,000,000, respectively. These amounts include amortization of past service cost. Costs of the retirement plans are accrued in accordance with an actuarial cost method (entry age normal method). The Company makes contributions to the plans equal to the amounts accrued for pension expense. A comparison of accumulated plan benefits and plan net assets for the Company's defined benefit plans is presented below:

	In Thousands	
January 1,	**1980**	1979
Actuarial present value of accumulated plan benefits:		
Vested	$693,000	$606,000
Nonvested	53,000	48,000
Total present value of accumulated plan benefits	$746,000	$654,000
Net assets available for benefits	$797,000	$652,000

The assumed rate of return used in determining the actuarial present value of accumulated plan benefits was 7 percent in 1980 and 1979. The actuarial present values are based on historic pay as prescribed by the Financial Accounting Standards Board.

Note 10
Quarterly Financial Data (unaudited)
Quarterly financial data for the four quarters of 1980 and 1979 are shown in the table below. Due to the seasonal nature of the utility business, operating revenues, operating income, and net income are not generated evenly by quarter during the year. The Company's common stock is traded on the New York and Pacific Stock Exchanges. The approximate number of common stockholders of record as of December 31, 1980 was 261,000. Dividends are paid on a quarterly basis and there are no restrictions on present or future ability to pay dividends.

	In Thousands (except per share amounts)			
	4th	3rd	2nd	1st
1980				
Operating Revenues	$1,485,740	$1,280,296	$1,163,692	$1,329,171
Operating Income	$ 133,125	$ 140,193	$ 146,103	$ 153,726
Net Income	$ 123,377	$ 145,133	$ 124,705	$ 131,555
Earnings Per Common Share	$ .80	$ 1.00	$ .86	$ .93
Dividend Declared	$ .65	$ .65	$ .65	$ .65
Common Stock Price				
High	$ 22⅛	$ 24¾	$ 24¾	$ 23¼
Low	$ 19⅝	$ 21⅜	$ 20¼	$ 19¼
1979				
Operating Revenues	$1,243,282	$1,086,595	$ 980,513	$1,054,079
Operating Income	$ 117,006	$ 140,538	$ 129,540	$ 128,819
Net Income	$ 101,264	$ 123,312	$ 118,000	$ 115,658
Earnings Per Common Share	$ .71	$ .98	$ .94	$ .92
Dividend Declared	$ .61	$ .61	$ .58	$ .58
Common Stock Price				
High	$ 23⅞	$ 24¼	$ 24⅛	$ 25⅛
Low	$ 21⅝	$ 22⅜	$ 21⅝	$ 22⅛

Supplemental Information Required by Financial Accounting Standards Board Statement No. 33 (unaudited)

For many years the purchasing power of the dollar, measured by consumer and wholesale price indices, has declined each year. This decline in purchasing power of the dollar is commonly called "inflation."

Many complex theories have been proposed in an attempt to eliminate the inflation component from reported net income, but no solution has emerged that commands general acceptance. In 1979 the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 33 requiring that certain supplemental financial information be printed showing historical information converted to two bases – constant dollars and current costs – using specified techniques.

Constant dollar amounts so required and as reported herein represent historical amounts converted to dollars having approximately the same purchasing power as the real dollar had in mid-1980 as measured by the Consumer Price Index for All Urban Consumers.

Current cost dollars as required by FASB No. 33 purports to represent the price in current dollars the Company would expect to pay for its assets if it could obtain them at today's prices. Because of siting, environmental and other problems involved in constructing property today that were not present when the Company's plant was originally constructed, there is no reasonable way for the Company to estimate the cost of replacing its assets. Therefore, for purposes of the current cost calculation, the Handy-Whitman Index of Public Utility Construction Costs for the Pacific Coast Division was applied to historical cost of surviving plant in developing the required current cost. This results in current cost calculations being computed from a construction index whereas constant dollar calculations are computed from an overall index.

Following FASB No. 33 requirements, the only amounts adjusted in arriving at the net income amounts adjusted for changing prices were net utility plant and depreciation expenses. As prescribed in Statement No. 33, income taxes were not adjusted.

The current year's provisions for depreciation on the constant dollar and current cost amounts of utility plant were determined by applying the Company's depreciation rates to the constant dollar and current costs.

The Company has serious reservations as to whether the required supplemental financial information is appropriate for measuring the impact of inflation on a utility regulated, as PG&E is, on a cost-of-service basis. This information is presented solely because it is required to be presented. It should be clearly understood that the required information is complicated, difficult to understand and because of the permitted subjectivity inherent in developing this prescribed information unwarranted comparisons and inferences may result.

Consolidated Statement of Income from Continuing Operations Adjusted for Changing Prices As Required By FASB Statement No. 33

	In Thousands		
For the Year Ended December 31, 1980	Conventional Historical Cost	Constant Dollar	Current Cost
Operating Revenues	$5,259,000	C$5,259,000	C$5,259,000
Operation, Maintenance and Other	4,453,000	4,453,000	4,453,000
Depreciation	281,000	632,000	856,000
Total	4,734,000	5,085,000	5,309,000
Income from continuing operations (excluding adjustment to net recoverable cost)	$ 525,000	C$ 174,000*	C$ (50,000)
Increase during the year in specific prices of utility plant**			C$1,543,000
Adjustment to net recoverable cost		C$ (666,000)	215,000
Effect of increase in general price level			(2,200,000)
Excess of increase in general price level over increase in specific prices after adjustment to net recoverable cost			(442,000)
Reduction of purchasing power loss through debt financing		656,000	656,000
Net		C$ (10,000)	C$ 214,000

C$ – Dollars having approximately the same purchasing power as the real dollar had in mid 1980.

*Including the adjustment to net recoverable cost, the loss from continuing operations on a constant dollar basis would have been C$492,000,000.

**At December 31, 1980, current cost of utility plant, net of accumulated depreciation was C$19,566,000,000 while historical cost or net cost recoverable through depreciation was $9,071,000,000.

Five-Year Comparison of Selected Supplementary Consolidated Financial Data Adjusted for Effects of Changing Prices As Required by FASB Statement No. 33

	In Thousands (Except per share amounts)				
For the Years Ended December 31,	**1980**	1979	1978	1977	1976
Operating Revenues	**C$5,259,000**	C$4,954,000	C$4,508,000	C$4,936,000	C$4,414,000
Historical Cost Information Adjusted for General Inflation					
Income from continuing operations (excluding adjustment to net recoverable cost)	**C$ 174,000**	C$ 244,000			
Income per common share (after dividend requirements on preferred stock and excluding adjustment to net recoverable cost)	**C$ .56**	C$ 1.35			
Net assets at year-end at net recoverable cost	**C$3,559,000**	C$3,640,000			
Current Cost Information					
Income from continuing operations (excluding adjustment to net recoverable cost)	**C$ (50,000)**	C$ 11,000			
Loss per common share (after dividend requirements on preferred stock)	**C$ (1.38)**	C$ (.90)			
Excess of increase in general price level over increase in specific prices after adjustment to net recoverable cost	**C$ (442,000)**	C$ (651,000)			
Net assets at year-end at net recoverable cost	**C$3,559,000**	C$3,640,000			
General Information					
Reduction of purchasing power loss through debt financing	**C$ 656,000**	C$ 720,000			
Cash dividends declared per common share	**C$ 2.60**	C$ 2.70	C$ 2.73	C$ 2.72	C$ 2.72
Market price per common share at year-end	**C$ 19.58**	C$ 24.70	C$ 27.06	C$ 31.82	C$ 32.75

C$—Dollars having approximately the same purchasing power as the real dollar had in mid 1980.

Average consumer price index Base year 1967—100	**246.8**	217.4	195.4	181.5	170.5

DIRECTORS AND OFFICERS

Directors

John F. Bonner
Executive Consultant and Former President and Chief Executive Officer, Pacific Gas and Electric Company

Richard P. Cooley 1, 4
Chairman of the Board and Chief Executive Officer, Wells Fargo Bank, N.A.

Charles de Bretteville 3, 4
Former Chairman of the Board, The Bank of California, N.A.

Myron Du Bain 1, 3
Chairman of the Board, President and Chief Executive Officer, Fireman's Fund Insurance Companies

Alfred W. Eames, Jr. 1, 2
Former Chairman of the Board, Del Monte Corporation (food products and related services)

Lewis S. Eaton 2
Chairman of the Board and President, Guarantee Savings and Loan Association

Robert B. Hoover 3
Chairman of the Board and Chief Executive Officer, The Pacific Lumber Company

L. W. Lane, Jr. 4
Chairman of the Board, Lane Publishing Company

Doris F. Leonard*
Secretary-Treasurer and Partner, Conservation Associates (park and land acquisition)

Leslie L. Luttgens 3
San Francisco Bay Area Community Leader

Richard B. Madden 2
Chairman of the Board and Chief Executive Officer, Potlatch Corporation (diversified forest products)

Frederick W. Mielke, Jr. 1, 4
Chairman of the Board and Chief Executive Officer, Pacific Gas and Electric Company

Mervin G. Morris 3
President, Morris Management Company

Richard H. Peterson
Former Chairman of the Board, Pacific Gas and Electric Company

Wilson C. Riles 2
California State Superintendent of Public Instruction

Barton W. Shackelford 1
President and Chief Operating Officer, Pacific Gas and Electric Company

Emmett G. Solomon 1, 4
Former Chairman of the Board, Crocker National Bank

John Lyons Sullivan 2, 4
Rancher and Chairman Emeritus, California Canners and Growers (cooperative canner of fruits and vegetables)

1 Member Executive Committee
2 Member Audit Committee
Richard B. Madden, Chairman
3 Member Compensation and Management Development Committee
Charles de Bretteville, Chairman
4 Member Advisory Nominating Committee
Frederick W. Mielke, Jr., Chairman
*Retired from the Board in February, 1981

Officers

Frederick W. Mielke, Jr.
Chairman of the Board and Chief Executive Officer

Barton W. Shackelford
President and Chief Operating Officer

Stanley T. Skinner
Executive Vice President

John A. Sproul
Executive Vice President

John S. Cooper
Senior Vice President Personnel

Malcolm H. Furbush
Senior Vice President and General Counsel

Ellis B. Langley, Jr.
Senior Vice President Operations

Malcolm A. MacKillop
Senior Vice President Corporate Relations

George A. Maneatis
Senior Vice President Facilities Development

G. Stanley Bates
Vice President General Construction

Donald A. Brand
Vice President Engineering

Howard P. Braun
Vice President Electric Operations

Robert W. Brooks
Vice President Gas Planning and Acquisition

Richard A. Clarke
Vice President and Assistant to the Chairman

George F. Clifton, Jr.
Vice President Customer Operations

Nolan H. Daines
Vice President Planning and Research

Joseph Y. De Young
Vice President Division Operations

James T. Doudiet
Vice President Finance and Treasurer

William M. Gallavan
Vice President Rates and Valuation

Grant N. Horne
Vice President Public Relations

Elmer F. Kaprielian
Vice President Fuels Planning and Acquisition

John E. Koehn
Vice President Governmental Relations

Howard M. McKinley
Vice President Gas Operations

Richard K. Miller
Vice President General Services

Robert Ohlbach
Vice President and General Attorney

Frank A. Peter
Vice President and Comptroller

James O. Schuyler
Vice President Nuclear Power Generation

John F. Taylor
Vice President and Corporate Secretary

William H. Wallace
Vice President Computer Systems and Services

Mason Willrich
Vice President Corporate Planning

David B. Allison
Assistant Secretary

Brian L. McGrath
Assistant Secretary

Anthony J. Duffy
Assistant Treasurer

Gary E. Lavering
Assistant Treasurer

Gordon R. Smith
Assistant Treasurer

Schedule of Dividend
Payment Dates—1981

Common Stock
January 15
April 15
July 15
October 15

Preferred Stock
February 17
May 15
August 15
November 16

Common stock of the Company is listed on the New York and Pacific Stock Exchanges. Preferred stocks of the Company are listed on the American and Pacific Stock Exchanges.

Proxies will be solicited by the Board of Directors for the annual meeting to be held at the Masonic Auditorium 1111 California Street, San Francisco, California, on Wednesday, April 15, 1981, at 2:00 p.m. In connection with such solicitation, it is expected that the proxy statement and form of proxy will be mailed to stockholders on or about March 10, 1981.

L. H. Gunter
Office of the Company
San Francisco

Wells Fargo Bank, N.A.,
San Francisco

Pacific Gas and Electric Company
77 Beale Street, San Francisco
California 94106

A copy of the Company's report for 1980 filed with the Securities and Exchange Commission on Form 10-K will be provided to stockholders upon written request to the Corporate Secretary at the above address.

Pacific Gas & Electric Company
77 Beale Street
San Franciso, CA 94106

Bulk Rate
US Postage Paid
Pacific Gas &
Electric Company