ALJ/km

Decision 93887 December 30, 1981 ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority, among other things, to increase its rates and charges for electric and gas service. (Electric and Gas)	Application 60153 (Filed December 23, 1980)
Application of PACIFIC GAS AND ELECTRIC COMPANY for authority, among other things, to increase its rates and charges for electric service. (Electric)	Application 58545 (Filed December 26, 1978)
Application of PACIFIC GAS AND ELECTRIC COMPANY for authority, among other things, to increase its rates and charges for gas service. (Gas)	Application 58546 (Filed December 26, 1978)

(Appearances are listed in Appendix A.)

I N D E X

INTERIM OPINION

I. Summary of Decision

In this general rate case decision, we grant Pacific Gas and Electric Company (PG&E) an increase of $656.2 million per year. (In addition, the Economic Recovery Tax Act of 1981 (Tax Act), passed by Congress, requires an additional increase in rates, to take effect on January 1, 1982, of $177.4 million.) The $656.2 million is far less than PG&E requested, and it will require PG&E to manage its productivity closely. At the same time, the amount is far more than PG&E ratepayers--residential, business, industrial, and agricultural--will find easy to pay.

We are required by law (see Public Utilities (PU) Code Section 451) to ensure that investor-owned utilities provide adequate and reliable service at rates that are just and reasonable. We must, therefore, seek to maintain the financial health of California utilities so that they can provide good service,--but at the lowest possible rate burden on the customer. In economic times like these, this is an extremely difficult balance to strike. In 75 days of hearings, we have reviewed in great detail every dollar requested by PG&E, and we have measured it against this standard. Our decision today is the result of that intensive effort. We emphasize in our decision the importance of good management of all utilities. The recent management audit of PG&E by Cresap, McCormick and Paget (CMP) has offered specific recommendations as to how PG&E can, through aggressive and prudent management, improve its productivity and reduce its overall operating costs. We reiterate our expectation that PG&E will put into effect all sound recommendations to improve productivity.

The reasons for the increases in this decision lie in the condition of the nation's economy over the last several years, and especially since PG&E's last general rate increase two years ago. The increases over the last two years have been due to increases in fuel cost--the cost of oil and natural gas--over which we have little control. General rate cases deal with all other costs such as labor, equipment, and the cost of money. In 1979 we made the best estimates we then could of the cost of these items for 1980 and 1981, and we set rates on the basis of these estimates. As we now know, our estimates were low for many items. For example, we projected labor cost increases at 7% and they were actually 10.4% in 1980 and 12.2% in 1981. The cost of debt, estimated in 1979 to be 9.0%, was actually 13% in 1980 and 16% in 1981.

PG&E also had to borrow substantial amounts of money in 1980 and 1981 because of a construction program started in previous years that includes several large, expensive projects such as Diablo Canyon and Helms. We do not and have never permitted such construction work in progress (CWIP) to go into rate base, and we reject that concept again today. Nevertheless, the carrying costs of these projects have been a major financial strain on PG&E, especially at such high interest rates. We do not today judge the prudence of PG&E's expenditures on these projects. That review will take place when they have been completed and are used and useful to ratepayers.

In addition, the delays in bringing Diablo Canyon on line have reduced PG&E's anticipated reserve margin and have caused PG&E to run older, oil- and gas-fired power plants more than anticipated. We are in this decision authorizing substantial increases in maintenance expenses to ensure that these older facilities, and thus PG&E's entire system, will continue to provide reliable service to PG&E's customers. We are also authorizing significant increases in expenditures on cost-effective load management programs to strengthen the system's reliability and flexibility during the coming years.

The return on equity granted in this decision reflects current financial reality. Long-term utility debt has been commanding interest rates of 15%-17% in the market over the last year. Massive federal government borrowing to finance the budget deficit has further bid up borrowing costs and reduced available funds in financial markets and unfortunately may do so for some time. Equity is by definition a riskier investment and therefore requires a return that is somewhat higher.

In this decision we reject PG&E's proposals for various ratemaking changes such as allowance of CWIP in rate base and changed depreciation policies that many other state regulatory commissions permit to offset risk and increase cash flow. In declining to grant these measures which reduce risk to the utility by shifting it to the ratepayers, we recognize that a somewhat higher return on equity is reasonable. It should be noted that the authorized return on equity can be actually earned by the utility only if it succeeds in aggressive management of its costs of operation. We do not, however, grant the high return of 18% PG&E requested. The additional cash flow resulting from the Tax Act as well as the revenue stability from the Energy Revenue Adjustment Mechanism (ERAM) adopted herein should reduce PG&E's risk and thus the size of the return.

We take notice of the other decisions issued today in Applications (A.) 60863, 60961, and 59535 et al., which affect the total rates faced by customers of PG&E. The effective gas rates are shown in our decision on PG&E's Gas Adjustment Clause (GAC). The effective electric rates are illustrated in our decision on PG&E's Energy Cost Adjustment Clause (ECAC) application.

II. Introduction

A. PG&E's Request

On September 23, 1980, PG&E tendered for filing its notice of intention (NOI) to file a general rate increase application for authority to increase its base rates for electric and gas service in compliance with the requirements of Resolution M-4706, the Commission's Regulatory Lag Plan for major utilities. The tendered NOI was accepted for filing on October 24, 1980, as NOI 33. On December 23, 1980, PG&E filed its application requesting authority to increase its rates and charges for electric and gas service by $1,138,354,000 and $316,244,000, respectively, or a combined request of $1,454,598,000.

On August 27, 1980, PG&E filed Application (A.) 59902 seeking annual increases in electric and gas rates of $248.8 million and $66.9 million, respectively, to go into effect on January 1, 1981. PG&E states that the present application for $1.45 billion in annual electric and gas rate increases to go into effect on January 1, 1982, would be reduced by whatever increases are authorized as a result of A.59902. On February 4, 1981, in Decision (D.) 92656, the Commission authorized an increase of $121 million and $34 million for PG&E's jurisdictional Electric and Gas Department operations, respectively. This reduces the requested increase in this application to $1,017,278,000 for electric and $282,051,000 for gas for test year 1982. These requested increases were further reduced as a result of various stipulations to the Commission staff's (staff) estimates and transfer of issues to other proceedings to $912,308,000 for electric and $218,222,000 for gas.

For the second year of the two-year test period contemplated under the Commission's Regulatory Lag Plan, PG&E seeks to establish an additional set of electric and gas rates to become effective on January 1, 1983, to offset the impacts of the anticipated financial and operational attrition on PG&E's ability to earn a reasonable return on common equity in 1983. The application shows that this additional set of rates for 1983 would produce additional gross revenues above those proposed for 1982 for the Electric Department of $178,565,000 and for the Gas Department of $127,681,000.

Based on PG&E's estimates, as revised, PG&E would, under present rates, earn a 4.75% rate of return on rate base for its California jurisdictional electric operations for test year 1982 and a 6.03% rate of return on rate base on its gas operations for test year 1982. PG&E states that these rates of return on rate base are disastrously below fair and reasonable levels under present and foreseeable economic conditions. Without rate relief PG&E would be unable to pay its shareholders any return on their investment and would be unable to pay bond interest and preferred stock dividends without substantial cuts in operating expenses which, in turn, would adversely impact PG&E's ability to serve its customers.

PG&E considers this application first and foremost a financial application with the key emphasis directed to enabling PG&E to achieve a state of financial health for the first time in a decade. The key issues as perceived by PG&E are:

1. PG&E must be granted a rate of return on rate base that accurately reflects the actual cost of capital faced by PG&E.
2. The Commission must provide means for PG&E to improve its cash flow situation.
3. The Commission should adopt a workable mechanism to offset the effects of financial and operational attrition in the year following the test year.
4. Reasonable expense and rate base estimates must be adopted to enable PG&E to maintain a reasonable level and quality of service to its customers and also have an opportunity to earn the rate of return found reasonable.

5. The Commission should incorporate the fundamental changes in federal income tax law resulting from the recently signed Tax Act.

6. The Commission should adopt an electric revenue adjustment mechanism similar to the gas Supply Adjustment Mechanism (SAM).

7. The Commission should resist "quick fix" proposals to provide financial incentives and penalties for the supposed purpose of inducing desired management performances.

8. The Commission should critically review its staff's recommendations to reduce funds requested by PG&E to perform conservation and load management activities.

9. The Commission should explicitly adopt PG&E's marginal cost methodology.

10. The Commission needs to urge the California Energy Commission (Energy Commission) to work more closely with it in determining and implementing energy policy in this State.

B. PG&E's Electric and Gas Operations

PG&E is, and ever since October 10, 1905 has been, an operating public utility corporation organized under California law. It is engaged principally in the business of furnishing electric and gas service in California. It also distributes and sells water in some cities, towns, and rural areas, and produces and sells steam in certain parts of San Francisco.

PG&E distributes electric energy in 47 central and northern California counties and provides gas service in 39 northern and central California counties. As of December 31, 1979, PG&E served a total of approximately 3,366,000 customers in all classes of service, including residential, commercial, industrial, agricultural, streetlighting, resale, and others. PG&E's electric transmission and distribution networks are supplied from its hydroelectric generating plants, steam-electric generating plants, including geothermal and purchased power.

PG&E distributes gas in 37 counties and served approximately 2,805,000 gas customers as of December 31, 1979. PG&E's natural gas is presently supplied from three general sources: out-of-state gas supplied by El Paso Natural Gas Company (El Paso), Canadian gas supplied by Pacific Gas Transmission Company (PGT), a subsidiary, and California-produced gas. In order to supply peak demands and to assure the ability to buy out-of-state gas, PG&E has underground storage fields at Pleasant Creek, McDonald Island, and Los Medanos.

C. Procedural Summary

This proceeding was assigned to Commissioner Leonard M. Grimes, Jr. and Administrative Law Judges (ALJ) Kenji Tomita and Kenneth K Henderson. ALJ Tomita presided over the prehearing conferences, the revenue requirements, and conservation phases of this proceeding, and ALJ Henderson presided over the public witness testimony and rate design phase.

In accordance with the Regulatory Lag Plan, the first prehearing conference was held on January 5, 1981, in San Francisco. Public witness hearings were held in afternoon and evening sessions in Red Bluff, Stockton, Fresno, Monterey, and Oakland on March 3, 4, 5, 9, and 10, respectively. The second prehearing conference was held on March 13, 1981, with evidentiary hearings commencing on March 17, 1981, all in San Francisco.

On February 10, 1981, the staff filed a motion to consolidate the limited rehearing granted by D.91478 dated March 18, 1980, in A.58545 and 58546 with the proceedings in A.60153. The limited rehearing was granted for the purpose of allowing the parties to submit evidence and conduct cross-examination with respect to the limited issue of the most appropriate treatment of PG&E's distribution costs in the Commission's formulation of marginal cost rates. The staff's motion for consolidation was granted.

During the 70 days of evidentiary hearings, numerous witnesses representing PG&E, staff, Energy Commission staff, and several other interested parties presented testimony and were cross-examined on approximately 200 exhibits received into evidence on issues involving results of operations, rate of return, rate design, and conservation. The evidentiary hearings were completed and the matter submitted for briefing on July 24, 1981, two weeks beyond the contemplated submission date. Concurrent opening briefs were filed on August 28, 1981, by 19 parties to the proceeding and concurrent reply briefs were filed by 11 parties on September 14, 1981. (Appendix B lists parties filing opening and/or closing briefs.)

On October 19, 1981, the staff petitioned the Commission to reopen the proceeding for the purpose of receiving additional evidence relating to the impact of the Tax Act on the results of operations for test year 1982 and attrition year 1983. Since the Tax Act was signed on August 13, 1981, after the final hearing dates in this proceeding, we found the staff's petition reasonable and reopened hearings on November 9 and 10, 1981, for the purpose of receiving evidence on the limited issue of the impact of the Tax Act on the results of operations for test year 1982 and attrition year 1983 and the impact on rate of return resulting from increased cash flow.

Oral argument was held before the Commission en banc on November 12, 1981, at which time 16 parties participated. (Appendix C lists the participants.) The matter is now ready for decision.

Aside from the numerous public witnesses that testified at the public witness hearings, the Commission also received hundreds of petitions and letters from customers, as well as resolutions and statements expressing their concerns over PG&E's $1.4 billion request for rate relief. The Commission also received a substantial number of letters from stockholders who requested that the Commission treat PG&E's stockholders fairly in order to permit PG&E to raise the necessary capital to provide reasonable service to its customers.

III. Rate of Return and Cash Flow Proposals

PG&E views this 1982 test year general rate application as the key instrument by which it can begin to restore its financial health. It considers this general rate application to be first and foremost a financial application and that all other issues are subservient to, and dependent on, PG&E being able to achieve a state of financial health for the first time in almost a decade.

Consistent with the emphasis placed by PG&E on its requested rate of return and cash flow proposals, numerous parties participated extensively in this phase of the proceeding through testimony by expert witnesses, cross-examination, briefs, and by oral argument.

Complete rate of return showings were made by PG&E, California Association of Utility Shareholders (CAUS), and the staff. General Services Administration (GSA) presented evidence on the cost of equity capital and flotation cost and market pressure on new common stock offerings. Energy Commission presented testimony on increased returns on equity and/or rate base for investments or contracts for energy from preferred resources as well as other recommendations for adoption of a system of incentives or penalties for achieving certain desired goals. In addition to rate of return testimony, the above parties also offered testimony on PG&E's proposals to increase cash flow by allowing the inclusion of non-earning assets above a certain level in rate base, acceleration of book depreciation on electric production plant, and the ratable flow-through treatment of Investment Tax Credit (ITC).

James T. Doudiet, vice-president, Finance, and treasurer for PG&E testified on rate of return and on various proposals to increase cash flow. E. W. Meyer, vice-president, director, and manager of the utility corporate finance department of Kidder, Peabody & Co., Incorporated, an investment banking firm, testified about the change in the costs of all forms of new external capital since the last general rate case in 1979, the deterioration of the financial performance of the electric and combination electric-gas utility business, the inappropriateness of using comparative data within the industry to determine PG&E's cost of capital, and also on the problems of market saturation with utility securities.

At the second prehearing conference, Energy Commission and the Environmental Defense Fund (EDF) argued that changes in PG&E's resource plan would cause substantial changes in PG&E's financing and cash flow requirements and, therefore, PG&E's original presentation in Exhibit 1, based on an early 1980 resource plan, no longer reflected PG&E's current financial situation. PG&E was ordered by the ALJ to submit a revised exhibit using a more recent resource plan to alleviate the concern expressed by Energy Commission, EDF, staff, and other parties.

Doudiet's revised exhibit (Exhibit 26), based on an informal February 1981 resource plan, shows that estimated construction expenditures for the years 1981 and 1982 were $63 million and $246 million lower, respectively, than the original estimates. Projected financing requirements for 1981 showed a reduction of $170 million for bonds, $3 million for preferred stock, and $248 million for common stock, and for 1982, a reduction of $44 million for bonds, $55 million for preferred stock, and an increase of $17 million for common stock. Based on the financing costs of 13% for new debt and 12.75% for preferred stock assumed in the original filing, the revised cost of capital for 1982 would be 12.36% instead of the 12.41% shown in the application. However, from a March 1981 viewpoint, the cost of new debt and new preferred stock was estimated to be 15% and 14.75%, respectively, which according to witness Doudiet would justify a 17.5% cost of equity and an updated cost of capital of 12.75% for 1982 compared to the original estimate of 12.41%. In Exhibit 26 witness Doudiet stated that although the higher cost of capital is justifiable, he was not changing his recommended return on equity of 17% or the 12.41% rate of return on rate base to comply with the spirit of the Regulatory Lag Plan.

PG&E's Position

In order to restore its financial integrity and enable PG&E to provide the multitude of services demanded by its customers and its regulators, PG&E requests a rate of return on rate base that accurately reflects the actual cost of capital faced by PG&E. Although PG&E's chief financial witness Doudiet did not change his requested rate of return on rate base and return on common equity of 12.41% and 17%, respectively (Table III-1), he did testify that the current market situation would justify a higher return and the Commission should take these changed facts into consideration in arriving at its authorized rate of return for PG&E. PG&E, in its brief, argues that the Commission should find as just and reasonable a return on common equity of 18% and a return on rate base of 12.86%. PG&E states that such cost of capital calculation also assumes that the Commission will grant PG&E an effective operational and financial attrition mechanism which will enable it to earn the rate of return found just and reasonable during both the test and attrition years.

Table III-1

PACIFIC GAS AND ELECTRIC COMPANY

1982 Cost of Capital
Average Year Basis

Line No.		Capital Ratios (A)	Cost (B)	Weighted Cost of Capital (C)
1	Bonds	45%	9.34% a/	4.20%
2	Preferred Stock	14%	8.84% a/	1.24%
3	Common Equity	41%	17.00%	6.97%
	Total	100%		12.41%

a/ Assumes a 13% cost of new debt and a 12.75% cost of new preferred stock.

Revised 1982 Cost of Capital
Assuming New Debt and Preferred Stock
Are Issued at 15% and 14.75%

Line No.		Capital Ratios (A)	Cost (B)	Weighted Cost of Capital (C)
1	Bonds	45%	9.58% b/	4.31%
2	Preferred Stock	14%	9.03% b/	1.26%
3	Common Equity	41%	17.00%	6.97%
	Total	100%		12.54%

b/ Exhibit 26, page 3.

Doudiet testified that rating agencies and security analysts use the following measures in evaluating the financial health of a firm:

1. Return on equity earned.
2. Market-to-book ratio.
3. Percent of capital requirements generated internally.
4. Interest coverages both before and after taxes.
5. Quality of earnings generally measured by the ratio of Allowance for Funds Used During Construction (AFUDC) to earnings on common equity.

If PG&E were the only utility in poor financial health, the proper standards of these financial measures would be determined by the rest of the utility industry; however, since the utility industry as a whole is in poor financial health a standard based on these utilities would be inappropriate. Therefore, the witness testified that the best method currently available was to look at these measures in a historical context and to consider the relationships among them on a theoretical basis. In arriving at his recommended rate of return, Doudiet decided that it was necessary to find a time period when PG&E could reasonably have been considered financially healthy. He determined that the time frame between 1965 and 1969 would meet this requirement since it was prior to the time inflation became a serious problem to the utility industry. Table III-2 sets forth the various financial measures for PG&E during this period. It shows that the average annual inflation rate during this period was 3.4%; the average return on equity earned of 11.8% closely followed the return allowed; the average market-to-book ratio was 1.75 times; the average internal generation of funds was 55%; before tax coverage was 4.3 times; after tax average 3.3 times; and AFUDC averaged 7.4% of earnings.

Table III-2

PACIFIC GAS AND ELECTRIC COMPANY

Financial Measures
1965-1969

Line No.	Year (A)	Annual Inflation Rate (B)	Return on Equity Allowed (C)	Return on Equity Earned (D)	Market-to-Book Ratio (E)	Internal Generation (F)	Before Tax Coverage (G)	After Tax Coverage (H)	AFUDC as % of Earnings (I)	Embedded Cost of Debt (J)
1	1965	1.5%	11.8%	11.5%	1.98X	49.6%	4.7X	3.5X	7.1%	3.71
2	1966	3.1	11.8	11.7	1.83	51.2	4.5	3.5	6.0	3.88
3	1967	2.8	11.8	12.4	1.73	55.8	4.2	3.4	10.3	4.09
4	1968	4.2	11.8	12.0	1.76	62.7	4.1	3.2	6.4	4.26
5	1969	5.4	11.8	11.6	1.44	54.7	3.8	2.9	7.2	4.60
	Average	3.4%		11.8%	1.75X	54.8%	4.3X	3.3X	7.4X	4.11%

While PG&E is not seeking to match the standards for 1965-1969, witness Doudiet testified that such standards should be used as guidelines. Considering the high cost of money and the large volume of financing confronting PG&E, Doudiet recommends the adoption of the following measures as being appropriate if PG&E is to be considered a financially healthy utility:

1. Earn the allowed rate of return.
2. Market-to-book ratio slightly greater than one.
3. Internal generation of funds should be a minimum of 50%.
4. Interest coverage should be 3.5-3.75 times before taxes and 3.0 times after taxes.
5. AFUDC should never be greater than 20% of earnings.

In arriving at his determination that a 17% return on common equity was reasonable for test year 1982, Doudiet used the risk premium method to confirm his opinion that there has been a 200 basis point increase in overall cost of capital since the last general rate proceeding in 1979. The risk premium method assumes that the return on common equity is at some consistent risk premium above the embedded cost of debt. The rise in the embedded cost of debt to PG&E resulting from inflation in recent years is considered an excellent proxy for a direct measure of the rise in equity cost to PG&E brought about by inflation during the same period.

Table III-2, column D shows that the average return on common equity for the period 1965-1969 was 11.8%, and in column J that the average embedded cost of debt was 4.11% for the period. Table III-3 develops the adjusted rate of return on common equity necessary for each of the years 1970 through 1982 if the same average spread between embedded cost of debt and return on common equity for the period 1965-1969 is to be maintained. This methodology assumes that as inflation increases the embedded cost of debt it would also have the same impact on the cost of equity. Witness Doudiet further

Table III-3

PACIFIC GAS AND ELECTRIC COMPANY

Adjusted Rate of Return on Equity
1970-1982

Line No.	Year	Basic Cost of Equity (1965-1969) (A)	Year-end Embedded Cost of Debt 1970-80 Actual 1981-82 Estimated (B)	Adjustment C = B - 4.11% (C)	Adjusted Rate of Return on Equity D = A + C (D)
1	1970	11.8%	4.98%	.87%	12.67%
2	1971	11.8	5.36	1.25	13.05
3	1972	11.8	5.50	1.39	13.19
4	1973	11.8	5.79	1.68	13.48
5	1974	11.8	6.54	2.43	14.23
6	1975	11.8	6.76	2.65	14.45
7	1976	11.8	6.94	2.83	14.63
8	1977	11.8	7.07	2.96	14.76
9	1978	11.8	7.26	3.15	14.95
10	1979	11.8	7.54	3.43	15.23
11	1980	11.8	8.19	4.08	15.88
12	1981*	11.8	9.05	4.94	16.74
13	Updated	11.8	9.18	5.07	16.87
14	1982*	11.8	9.62	5.51	17.31
15	Updated	11.8	9.97	5.86	17.66

* As originally filed.

testified that use of the embedded cost of debt was superior to the use of incremental cost of debt since the embedded cost of debt is more stable and a long-run measure of the cost of debt to PG&E. Under this concept, Table III-3 shows that the appropriate return on common equity would be 16.87% for 1981 and 17.66% for 1982.

Based on a 17% return on common equity, Doudiet further testified that the market-to-book ratio would be 99%, after tax interest coverage would be 2.95 times, and internal generation of funds before cash flow improvements would be 43.5% and 53.1% of capital requirements with cash flow improvements. Doudiet also emphasized the importance of adopting an adequate mechanism to deal with inflation and conservation effects particularly in the interim year between rate cases. He supported the adoption of step rates as being preferable to a return on equity adjustment applicable to both years as used in D.91107 for 1980 and 1981. He further testified that due to spiraling fuel costs, financial costs have become a lesser portion of total costs, which creates an opportunity for the Commission to better balance the investor's and consumer's interests in a way not possible a few years ago. He estimated that a 1% increment in return on equity would require only a 1.17% increase in electric revenues and a 0.45% increase in gas revenues.

In addition to earning a fair and reasonable return on common equity, Doudiet testified that PG&E must realize cash flow sufficient to support its ongoing operations and construction program. If the cash return on investment is inadequate, PG&E must return frequently to the financial markets even though its recorded return on common equity may be quite high. Among the major utilities, witness Doudiet contends that PG&E ranks 45 out of 50 in cash flow as a percentage of average capitalization. Even if PG&E were allowed and earned a 17% return on common equity, it would need to go to the security markets every 2½ months with a security offering averaging $200 million. PG&E states that it needs cash flow improvements of sufficient magnitude to eliminate one security offering each year or approximately $200 million additional annual cash flow.

In Table 25 of Exhibit 26 witness Doudiet shows that out of 52 regulatory jurisdictions, 48 permit all or partial normalization of the benefits of ITC, 47 permit all or partial normalization of tax depreciation, and 19 permit construction work in progress (CWIP) which provides a cash benefit. PG&E requests that in order to improve its cash flow, the Commission approve its proposals (a) to adopt a nonearning assets ratio (NEAR) of 10%, which would limit AFUDC as a percentage of earnings to 20%; (b) allow depreciation on some plant on a marginal basis; and (c) allow a portion of the ITC (6% portion) be ratably flowed through for ratemaking. PG&E contends that these cash flow improvements would reduce the amount of external financing, reduce the risk of market saturation with PG&E securities, and result in the eventual improvement of its bond and preferred stock ratings to a solid AA level rather than the A level at which they now trade.

Meyer supported Doudiet's testimony on the financial deterioration of the electric and combination electric/gas utility industry, the problems of market saturation with utility securities, and the increase in capital costs resulting from double-digit inflation. It was also Meyer's opinion that it would take a long time to eliminate the root causes of inflation and that we may expect long-term interest rates and inflation rates to remain at double-digit levels through 1982.

For the period 1969-1979 Meyer's exhibit shows that earnings per share for Moody's 24 electric utilities have increased by only 2.65% annually due to the poor returns on equity earned during this period. Furthermore, because of the poor prospects for growth in earnings, the market price of common stock declined so that the price earnings ratio of Moody's 24 electric utilities index fell from 11.47 times in 1970 to 6.74 times in 1979. Although utilities increased dividends to the extent possible to meet current yield requirements of investors and to minimize the diluting impact of selling new common stock below book value, this could not stem the tide of declining stock prices. Also compounding the problem of declining growth, the quality of earnings deteriorated over this period jeopardizing the ability of utilities to generate cash to pay the all important dividends. For 1979 Meyer estimated that cash dividends were 130% of earnings before noncash AFUDC credit for Moody's 24 electric utilities. During the period 1974-1980 only 112 new common stock offerings out of a total of 550 realized net proceeds above book value, and in 1980 only two of 60 offerings sold at or above book value. Meyer testified that the results would have been worse if the utilities had not increased dividends, and reduced financial leverage and capital requirements.

Staff Position

A. Rate of Return - D. Gardner

The staff rate of return witness D. Gardner revised her recommended rate of return from 11.57% to 11.61% for 1982 and from 11.70% to 11.89% for 1983 based upon the higher financing costs experienced by PG&E on its March 1981 preferred stock and April 1981 debt offerings, while holding her recommended return on common equity at the 15% level recommended in her exhibit (Exhibit 29). Gardner further recommended that these cost figures should be revised to reflect the actual cost of new debt and preferred stock offerings issued prior to the date of decision. She further recommended that step rates for both financial and operational attrition be adopted in order to better enable PG&E to maintain stable earnings for the two years. Prior to authorizing step rates for 1983, she recommended that the staff Rate of Return Unit review PG&E's actual financial costs for 1982 and adjust for any differential between adopted interest and preferred dividend rates and the actual costs experienced by PG&E in 1982. Under such procedure, the ratepayers would be protected if the capital markets improved and interest rates declined and PG&E would have an opportunity to recover all current interest and dividend costs without waiting for the next general rate proceeding.

Staff agreed with PG&E on the appropriate capital ratios to be adopted for the test year and were in substantial agreement on the cost of debt and preferred stock to be used in the cost of capital computation. The only major area of difference was in the return on common equity requested by PG&E. The staff witness testified that her return on common equity recommendation is by necessity a matter of informed judgment and that she was guided in her analysis by the standards established by the U.S. Supreme Court decisions and by prior decisions of this Commission. Among the factors considered in arriving at her recommended return on common equity are:

1. PG&E's past earnings performance and financial history.
2. Bond ratings and interest coverage.
3. Capital structure.
4. Market data regarding common stock.
5. Earnings of comparable utilities.
6. Balancing the interest of consumers with interest of stockholders.
7. Size of capital requirements.
8. Economic conditions.
9. Commission's Regulatory Lag Plan and balancing accounts.

B. PG&E's Historical Financial Analysis - W. Thompson

Staff witness W. Thompson presented an analysis of PG&E's historical financial position during the period 1967-1979. For the period 1973-1979 common shares outstanding grew by an average compound growth rate of 9.3% compared to a 0.8% rate for the period 1967-1972. Moreover, during 1973 the market value of PG&E's stock declined to less than book value and has consistently sold for less than book value since the 1973 decline. Thompson further stated that if all the new issues of stock since 1973 had sold at book value, the year-end book value in 1979 would be $34.29 instead of the recorded book value of $29.83 per share at December 31, 1979, a loss of $4.46 per share due to dilution.

Thompson said that construction of the Diablo Canyon Plant (Diablo) was a major factor contributing to PG&E's need to go to the equity market for additional equity financing. (Diablo was responsible for 31% of PG&E's external financing during this period.) The witness observed that cost overruns on Diablo, low earnings, and balancing account undercollections have been a major drain on internal cash generation. He then proceeded to describe the actions taken by the Commission to alleviate the problems created by the new inflationary environment by adoption of balancing accounts to ensure that utilities can recover certain major classes of expenses and the adoption of the Regulatory Lag Plan to expedite rate relief. While balancing account undercollections and the continued gap between earned and authorized return have had a material impact on cash flow for the 1976-1979 period, Thompson was of the opinion that a revised ECAC procedure, rate base offset procedure, and rate recognition for financial and operational attrition should tend to close the gap between earned and authorized return and correct undercollection imbalances in the future.

C. PG&E's Cash Flow
<u>Proposals - R. Czahar</u>

Staff witness Czahar presented his analysis of PG&E's request for increased cash flow. He concurred with witness Thompson that construction of Diablo was one of the principal causes for PG&E's cash flow problems. Czahar testified that with the expected start-up of Diablo in 1982, and the attendant improvement in cash flow and earnings, he found PG&E's pessimistic financial outlook for the near term perplexing. He testified that with the change in resource plan between May and December 1980, and the cancellation of the Allen-Warner Valley Coal Project in early 1981, PG&E's capital requirements for test year 1982 declined by 18% with a consequent increase in internal cash generation as a percentage of capital needs from 35% to 43% without any regulatory innovations assuming PG&E earns its 17% requested return on common equity. Czahar concluded that assuming (a) Diablo will be operational and in rate base by the end of 1982, (b) PG&E rates are set on a basis ensuring that it will have an opportunity to earn its authorized rate of return, and (c) PG&E is cautious about committing itself to additional capital intensive projects in the near future, PG&E should be able to generate sufficient internal cash flow to regain its financial stability. He therefore was of the opinion that the drastic measures proposed by PG&E to improve cash flow were unnecessary.

CAUS' Position

CAUS, a nonprofit organization whose members are shareholders of California public utility companies, presented Ross Cadenasso, a corporate financial consultant as its witness. Cadenasso testified that during the period 1967-1972 PG&E's shareholders were able to earn a return on their investment commensurate with that earned by nonregulated enterprises. However, from 1973-1980 PG&E shareholders and utility shareholders generally have earned returns on equity far below the returns earned by nonregulated enterprises. The nonregulated companies demonstrated an ability to cope with inflation and were able to increase their average return on equity by 26% from 11.7% in the 1967-1972 period to 14.8% for the 1973-1980 period. The Commission in the meanwhile raised the average allowed return on equity for PG&E by 6% from 11.8% to 12.5% for this period and PG&E's actual earnings averaged only 11% before adjusting for dilution incurred by the sale of new shares below book value and 9% after adjusting for dilution.

Cadenasso further testified that PG&E's coverage ratios, earnings quality, and internal generation of funds continued to decline in this latter period. PG&E was forced to sell 58.7 million shares of stock below book value to finance its customers' demand for service. CAUS, in its exhibit, made various computations to show the losses suffered by PG&E shareholders because of low earnings during the period 1974-1980, and also the consequent losses suffered due to the sale of new stock below book value during this period and the resultant dilution of the shareholders' interest in PG&E.

Cadenasso recommends that the Commission find an 18% return on common equity as reasonable for PG&E without cash flow improvements and a 17.5% return on common equity with cash flow improvements. It was Cadenasso's opinion that even if these returns are actually earned by PG&E, it was unlikely that PG&E would be able to sell new common stock at book value for some time since investors will want to see tangible results that the Commission's philosophy of regulation does not penalize stockholders. He also recommended the adoption of step rates and indexing in developing attrition year rates to enable PG&E to recover estimated cost increases. He further called upon the board of directors of utility companies to cut back investment in new plants to the level supportable by internal generation of funds and prudent borrowing and to stop the sale of new stock as long as such stock is selling below book value.

GSA's Position

John Rettenmayer, testifying on behalf of GSA, stated that the bare-bone cost of equity for PG&E is estimated to be in the range of 15.4% to 16.4% with a best estimate of 15.9%. He used the discounted cash flow (DCF) analysis to determine the cost of existing equity. As a further check upon the investor's discount rate for PG&E, as determined by the DCF analysis, Rettenmayer used the capital asset pricing model technique.

The DCF model recognizes that the current market price of a share of common stock equals the present value of the expected future stream of dividends, and the future sale price of the share, both discounted at the investor's discount rate. The consensus investor's discount rate is the cost of attracting investor's capital and, therefore, is the cost of capital to the firm. The analyst uses judgment in selection of the time period over which to determine currency of yield observations and dividend growth rate expectations likely to be held by investors. Based on the average yield of PG&E common over the 52-week period ending March 23, 1981, Rettenmayer determined that the appropriate current dividend yield was 11.9% and by addition of a 4% growth factor arrived at his 15.9% base cost of equity rate.

Philip R. Winter, the second GSA witness, testified concerning the effects of costs associated with the issuance of new shares and the effect of market pressure upon the new proceeds PG&E would receive from a new common stock offering. The witness concluded that an allowance of 3.5% of sales proceeds for flotation costs and .5% for market pressure were appropriate. Such allowance would apply only to new equity with the outstanding equity receiving the 15.9% bare-bone cost recommended by Rettenmayer, and the new equity a 16.4% return or a composite cost of 15.92% for 1982.

Mr. Chhabra, the third witness for GSA, testified against PG&E's proposal to include nonoperative CWIP in rate base. He stated that the proposal violated two principles of ratemaking: (a) that the ratepayer should bear the burden of only that property which is used and useful in providing service, and (b) one generation of ratepayers should not subsidize another. He further stated that the Federal Energy Regulatory Commission (FERC) allows additional CWIP, other than capital invested in projects for controlling pollution or converting oil- and gas-fired plant to other fossil fuels, in rate base under certain hardship conditions. The witness was not aware of any instance where FERC had allowed CWIP in rate base under such hardship conditions.

Energy Commission's Position

Energy Commission considers the 1982 and 1983 test years to be a watershed period for PG&E. PG&E's management decisions will determine whether 1982 is PG&E's best financial year in the 1980s and is followed by a period of declining health, or whether 1982 and the rest of the 1980s as well are a financially stable period for PG&E. PG&E faces the choice of building additional long-lead time base load plants which would risk financial deterioration later in the decade or take advantage of its improved financial situation to accelerate the development of shorter lead time conservation and alternative energy resources that can keep its financial condition relatively healthy. Energy Commission believes that this Commission should establish a system of incentives, both rewards and penalties, to encourage the development of preferred resources.

Energy Commission agrees that PG&E's financial condition has worsened in the last 10 years due to rising interest rates, attrition of earnings because of inflation, increased rate base between test years, and the increasing burden of financing nonearning assets--mainly large, long-lead time power plants before they become operational. The major cause of this increase in CWIP is attributable to Diablo and to a lesser extent the Helms Pumped Storage Project. When these two facilities become operational in 1982 and 1983, Energy Commission believes that PG&E's quality of earnings will improve and its financial condition will stabilize.

William B. Marcus testified on Energy Commission's proposals for a system of management incentives to encourage PG&E to take the course of investing in preferred resources rather than in large, long-lead time power plants and avoid the problems of large nonearning assets which hurt the quality of PG&E's earnings and result in a repetition of the financial problems of the 1970s. He further testified against adoption of PG&E's proposals for cash flow improvements since it was his belief that such proposals provided unbalanced incentives that promote conventional resource development. It was Marcus' recommendation that if the Commission finds that PG&E has a need for increased cash flow, it should be granted straightforwardly through an increased return on common equity and attrition adjustments that give PG&E a reasonable chance to earn its authorized return.

In addition, Marcus stated that cash flow relief should close out CWIP and Plant Held for Future Use (PHFU) accounts related to conventional projects no longer planned for service and also set clear incentives for preferred resource developments. He proposes, as incentives for investments in preferred resources, a 3% added return on common equity above the base return on common equity for all investments in preferred resources operative after December 1979, and, in addition, the rapid depreciation over eight years of such investments. This proposal recognizes the possible technical risk of developing such resources by reducing the life of such resources for ratemaking purposes and by increasing equity return.

For projects not involving capital investment by PG&E, Marcus proposes that the Commission establish a goal of 250 megawatts (MW) of contracts per year for alternative energy projects developed by others, excluding steam geothermal projects. If PG&E were to sign less than 160 MW of such alternative energy projects, it would be penalized 0.002% on rate base per MW of contracts signed below

160 MW, and if PG&E should sign more than 200 MW of contracts, it would receive an incentive payment of 0.002% on rate base per MW on contracts signed above 200 MW. Energy Commission's proposal also provides for a similar 0.002% on rate base per MW incentive for each MW where PG&E provides material noncapital services (maintenance contracts, feasibility studies, financing, or loan/bond guarantees). In order to motivate PG&E to not only sign contracts, but to ensure that the projects are actually developed, Energy Commission proposes an additional incentive payment of 0.003% on rate base per MW for each MW over 200 MW that is actually brought on line under contract in any one year. For the years 1982 and 1983 Energy Commission proposes a different formula for projects brought on line. Since PG&E forecasts that it expects to receive 55 MW of power in 1982 and 66 MW in 1983 from new preferred resource projects where PG&E is not the owner, Marcus recommends that the Commission should grant a rate of return increase on total rate base of 0.005% for each MW brought into service from a preferred resource above 80% of this amount. (80% of 55 = 42 MW for 1982, and 80% of 66 MW = 53 MW for 1983.) Under this proposal, if the forecasted projects are brought on line, PG&E would receive an extra 0.055% return on equity in 1982 and 0.065% in 1983 above the base amount granted by the Commission.

Energy Commission also proposes an incentive of $100,000 per thousand customers for reaching customers defined in the Zero Interest Program (ZIP) proceeding as renters or low income in order to encourage PG&E to take vigorous action to promote ZIP to these customers.

Energy Commission also recommends that conservation capital expenses and methane recovery projects from landfill, biomass, and feed lots should receive preferential rate treatment of 3% on equity and eight years' depreciation similar to that for the Electric Department, and that the Gas Department's rate of return also include a conservation incentive. Table III-4 sets forth a summary of Energy Commission's proposed incentives. Energy Commission's proposals relating to conservation incentives are discussed under Section VIII, Conservation.

Table III

CEC Proposed Incentives

Project	Incentive	Rate-Making Procedure	Rate Year	Additional PG&E Cash Flow	
A. Electric Projects:[a] Totally or partly owned by PG&E				1982 1983	
1. Operative after 12/19/79	3% ROR[b] added to common equity; depreciation over 8 years	Forecast plant eligible for incentive and include in rate base[c]	1982 - 1983	1.28[d] 2.62[d] Million 9.9[d] 20.64[d] Million	3% return on equity 8-year depreciation
2. Operative after 12/83	3% ROR added to common equity; depreciation over 8 years	Forecast projects eligible for incentives in applicable test year[c]	post '83	varies	
B. Electric Projects:[a] Customer owned, PG&E contract	• for signed contracts				
1. Performance from 10/80 to 9/81	0-160 MW = penalty .002 per MW 160-199 MW = no effect 200-plus MW = bonus .002 per MW	Adjustment to ROR for past performance; amount determined in this proceeding[f]	1982	varies	
2. Performance from 10/81 to 9/82, etc.	0-160 MW = penalty .002 per MW 160-199 MW = no effect 200-plus MW = bonus .002 per MW	Adjustment to ROR for past performance; amount determined during rate case proceeding in odd numbered years, by special appli-, cation or attrition proceeding in even years	post '82	varies	

Table III-4 [illegible]d.)

Project	Incentive	Rate-Making Procedure	Rate Year	Additional PG&E Cash Flow
	° for production brought on line			
3.	.005% increase to ROR per MW over 42 MW	Forecast now and adjust for actual performance during 1982 attrition proceeding	1982	$3.03 million
4.	.005% increase to ROR per MW over 53 MW	Forecast now and adjust for actual performance in 1983 rate case	1983	$3.58 million
5.	.003% per MW over 200 MW (annual)	Forecast and adjust for actual performance based on 200 MW goal	post '83	varies
	° for development assistance[g]			
1.	.002% increase to ROR per MW of facilities for which services provided	Adjustment to ROR for past performance; amount determined at attrition proceeding	'82-future	varies
C. ZIP loans targeted to low-income homeowners/renters	$100,000 per 1,000 eligible customers	ROR based on actual performance in prior year; amount to be determined in ZIP offset proceeding	'83-future	varies
D. Gas projects:[h] totally or partly owned by PG&E	3% ROR added to common equity; depreciation over 8 years	Forecast projects eligible for incentive in applicable test year	'82-future	varies

Table III-4 (Contd.)

a. Cogeneration, wind, small hydro, solar electric, biomass, steam and hot water geothermal, and conservation capital are eligible projects.

b. ROR = rate of return.

c. All forecasts for test years shall be determined during the rate case for the particular test year.

d. Approximation, from Ex. 94, Table 5, corrected by Ex. 96 and further corrected for delays in Geysers 16, 17, 18. (Ex. 51.) These calculations assume that the 1982 and 1983 electric plant qualifying for these incentives are $108,174,000 and $225,243,000, respectively and the 1982 and 1983 qualifying rate base is $103,829,000 and $206,528,000, respectively.

e. Cogeneration, wind, small hydro, solar electric, biomass, steam, and conservation capital are eligible projects.

f. If there is no attrition proceeding held in 1982, PG&E may file a separate application November 1, 1982.

g. Includes maintenance contracts, feasibility study financing, and loan or bond guarantees.

h. Methane recovery from biomass, landfill, and conservation capital (ZIP) are eligible projects.

As part of Energy Commission's proposal to improve PG&E's cash flow, witness Marcus recommended that PG&E be authorized to amortize over a four-year period all past expenditures on a list of projects which have been deleted from its resource plan or indefinitely postponed. The amount in question totals $126 million in CWIP and $6.7 million in PHFU. Energy Commission recommends that these amounts, less any AFUDC accruals included in such total, be amortized and recovered in rates. PG&E objected to the exclusion of AFUDC and the staff objected to the amortization without first determining whether ratepayers should bear any portion of such expenditures.

We will address the problems relating to the Humboldt Plant which are a part of the $126 million in a subsequent section. We do not believe it is appropriate to adopt Energy Commission's recommendation in this proceeding without permitting the staff to analyze and review the various properties included in witness Marcus' exhibit. We will require staff and PG&E to review Energy Commission's recommendations in relation to amounts held in CWIP or PHFU accounts relating to discontinued projects no longer in the resource plan with appropriate recommendations for disposition or retention of such amounts in the next general rate proceeding.

Industrial Users' Position

General Motors Corporation (GM), Kaiser Steel Corporation, Monsanto Company, and Union Carbide Corporation (Industrial Users) were active participants in the revenue requirement phase of this proceeding, putting special emphasis on opposing PG&E's NEAR adjustment and incremental depreciation proposals to increase cash flow. Industrial Users' witness Mark Drazen of Drazen-Brubaker & Associates, Inc., a utility rate and economic consultant, testified on certain of the criteria set forth by Doudiet as measures of financial health for PG&E. Drazen took exception to Doudiet's 3.50-3.75 times interest coverage requirement before taxes as being significantly higher than what rating agencies have apparently required for an AA rating. Drazen points out that the average coverage ratio for AA-rated utilities was 3.3 times in 1979 and that PG&E was able to maintain its AA rating with a pretax coverage ratio that was decidedly lower (2.8 times in 1979). Drazen also took exception to the high standards proposed by Doudiet for percentage of funds generated internally and the ratio of AFUDC to equity earnings. Drazen testified that if PG&E were to meet the standards would set forth by Doudiet, it may be that PG&E would be "too healthy" in that the costs to ratepayers of maintaining these standards exceed the savings they might realize. Drazen also points out that PG&E's presentation ignores its higher common equity ratio and its lower dividend payout ratio, both of which he considers important measures of financial health.

Although Industrial Users do not oppose PG&E's proposal for normalization of a portion of PG&E's investment tax, they strongly oppose PG&E's NEAR and incremental depreciation proposals on the following grounds:

1. PG&E fails to demonstrate the need for cash flow improvements.
2. The conservation and marginal cost rationale for these devices, as stated by PG&E, do not withstand the most cursory examination.
3. Though they produce relatively little after tax revenue for PG&E, the economic impact of such proposals upon PG&E's ratepayers is potentially devastating.

Other Parties' Positions

California Farm Bureau Federation (Farm Bureau) suggests in its brief that traditionally the Commission has found that reasonable rates of return for gas and electric utilities should be higher than for communications utilities. Farm Bureau argues that the riskiness of communications utilities has increased in the last decade, whereas the energy utilities have not experienced this type of explosive competition and have the advantages of various types of balancing accounts. Farm Bureau therefore argues that the rate of return granted in The Pacific Telephone and Telegraph Company's general rate case does not mandate a similar outcome in this case. Farm Bureau also opposes all three of PG&E's cash flow increase proposals as being gimmicks which have been previously rejected by the Commission. Farm Bureau agrees that PG&E is entitled to a return on investment which is fair to shareholders and which will allow PG&E to continue to attract capital at a competitive rate in amounts large enough to assure future service.

Toward Utility Rate Normalization (TURN) argues in its brief that PG&E's three cash flow increase proposals are unreasonable and unjustifiable. TURN argues that the need to eliminate one financing issue each year was accomplished by a change in the resource plan. TURN also opposes Energy Commission's alternative cash flow proposals as having the same problems as including CWIP in rate base. TURN contends that the 15% return on equity recommended by the staff is adequate, if not too generous.

EDF in its brief suggests the following actions by the Commission:

1. Denial of PG&E's cash flow mechanism and granting PG&E its full requested rate of return on equity.
2. Adopting a set of incentives designed to promote financially advantageous alternative energy sources.
3. Firmly penalizing PG&E for its failure to respond to previous Commission orders.

EDF states that its proposed actions depend on one another and cannot be considered separately. These actions are intended to deprive PG&E of its major excuses for failing to pursue economically optimal investment and to show shareholders and market analysts, as clearly as possible, that control of PG&E's economic fate lies squarely in the hands of PG&E's own management.

City and County of San Francisco (City) opposes PG&E's proposals to increase cash flow. City argues that PG&E's cash flow devices require ratepayers, through increased rates, to pay PG&E $359 million before taxes to provide it with additional capital. City further argues that a utility, as a general rule, has an obligation to raise the capital and that ratepayer contribution of capital is far more expensive than traditional financing.

City also argues that Energy Commission's cash flow proposals must be rejected. Energy Commission's witness points out the financial advantages to utility shareholders and ratepayers of a policy promoting conservation alternatives. City argues that if these financial advantages are real, further incentives simply provide a windfall to the utility. If these advantages do not exist, there should be no basis to provide added capital for these purposes.

Discussion

Staff, PG&E, and other major parties to this proceeding do not disagree with PG&E's estimated capitalization ratio for test year 1982 nor with the recognition of PG&E's actual cost of new debt and preferred stock issued in 1981. The following sets forth PG&E and staff's cost of capital estimates for 1982 on an average year basis after reflecting all new debt and preferred issues through July 1981:

PACIFIC GAS AND ELECTRIC COMPANY

1982 Cost of Capital
Average Year Basis

Line No.		Capital Ratio (A)	Cost (B)	Weighted Cost at 17% ROE (C)	Weighted Cost at 18% ROE (D)
	PG&E Position (revised)*				
1	Bonds	45%	9.38[a,b]	4.22%	4.22%
2	Preferred	14	8.98[b]	1.26	1.26
3	Common	41	-	6.97	7.38
4	Total	100%		12.45%	12.86%
	Staff Position				
5	Bonds	45%	9.34[a,b]	4.20%	
6	Preferred	14	8.97[b]	1.26	
7	Common	41	15.00	6.15	
8	Total	100%		11.61%	

a - The staff uses equal drawdowns on Pollution Control Bonds in 1981 through 1983 from funds in trust in its calculation of cost of debt, whereas PG&E accounts for the entire sum in 1981, as the entire amount goes into capitalization in 1981.

b - Also, the exclusion of issuance expenses for future issues in the staff's calculation of the cost of debt and preferred capital resulted in lower cost components than are projected by PG&E.

* - PG&E's original showing, Exhibit 26, Table 1:

	Capital Ratio	Cost	Weighted Cost
Bonds	45%	9.34%	4.20%
Preferred	14	8.84	1.24
Common	41	17.00	6.97
Total	100%		12.41%

Staff and PG&E have agreed that current costs incurred by PG&E on new bond and preferred stock issues should be recognized by this Commission in arriving at its adopted reasonable rate of return for test year 1982. Both PG&E and staff witnesses used an assumed 13% interest cost for new debt, and for preferred stock PG&E assumed a 12.75% dividend cost compared to the staff's estimate of 12.5% for 1981 and 1982. These interest and dividend costs are substantially below the actual costs experienced by PG&E in 1981 and below costs which PG&E can be reasonably expected to incur in test year 1982. We will adopt the staff's recommendation and recognize all actual new debt and preferred stock costs incurred by PG&E in 1981 in arriving at our test year debt and preferred stock cost factors. While we believe that there will be some moderation in interest and preferred dividend costs in test year 1982, we believe that both staff's and PG&E's estimates are overly optimistic. We will adopt as reasonable a 15% interest cost and a 14.75% preferred dividend rate for new debt and preferred issues in 1982.

The major area of difference in the rate of return recommendations of the various parties is the appropriate return on common equity. PG&E's risk premium analysis and GSA's DCF analysis are both formula-type approaches, whereas the staff and CAUS follow the more traditional informed judgment approach which relies on an analysis of extensive information available to the analyst. Although the formula approach offers an image of objectivity, consistency, and reliability for the future, it requires the making of assumptions which, in turn, requires the exercise of judgment. Based on the assumptions made, it is apparent that the answers can vary to fall within the equity range of 15% to 18% recommended in this proceeding. We believe that the input of the various parties has been constructive and of value to us in determining our adopted rate of return and return on common equity for PG&E. Our determination of a reasonable return on common equity will not, however, be based on adoption of any single formula or methodology.

Cash Flow Considerations

In conjunction with our determination of a reasonable rate of return on rate base and return on common equity for PG&E in this proceeding, it is also necessary to consider PG&E's various proposals to improve cash flow. While we may concur that it may be desirable to increase cash flow to reduce the amount of external financing necessary for PG&E to construct the facilities needed to provide service to its customers, we must also weigh the cost involved and the benefits to be achieved by adoption of such proposals. PG&E's proposals, if adopted, would require us to reverse various regulatory policies which have guided this Commission's actions in the past. Before abandoning such policies, we must be convinced that drastic action is necessary.

PG&E in its initial filing stated that it plans to sell at least five major security offerings in 1981, each of roughly $250 million in size, and that in 1982 a similar financing program would be needed. In order to avoid the flooding of securities in the securities market, PG&E stressed the importance of obtaining sufficient additional cash flow to eliminate the need for one financing offering of $250 million annually. To provide this additional cash flow, PG&E proposed the adoption of (a) NEAR, whereby all nonearning assets projected to exceed 10% of earning assets, rounded to the nearest $25 million, would be included in rate base, (b) the ratable flow-through treatment of the 6% ITC, with the original 4% being flowed through, and (c) incremental depreciation on electric production plant.

NEAR

PG&E seeks the adoption of its NEAR proposal to reduce the financial strains on PG&E whenever the ratio of nonearning assets exceeds a certain percentage of earning assets. Since nonearning assets provide no current cash flow to pay for the financing costs, the utility is placed under a heavy financial burden when the percentage of nonearning assets to earning assets becomes too great. Through adoption of a 10% NEAR, the portion of earnings for PG&E coming from AFUDC would be limited to about 20% and, therefore, enable PG&E to conform to one of the five standards of financial health testified to by Doudiet. Although the NEAR mechanism would be activated only when nonearning assets are large, PG&E claims that the adoption of such a mechanism would be looked upon favorably by investors as a positive measure taken by this Commission in restoring the financial health of PG&E.

As discussed previously, all of the parties strongly opposed PG&E's NEAR proposal as being contrary to the used and useful principle, arbitrary, an incentive to overbuild, and as a disincentive to control costs. A further criticism of the proposal was that it would result in a forced investment by today's ratepayers who may not be around when the plant is completed and who consequently would receive no benefits from such investment.

Ratable Flow-Through of ITC

The second PG&E cash flow proposal is to normalize the 6% ITC over the average life of the property. PG&E requests that it be provided the same ratemaking treatment for ITC as accorded other major energy utilities in California thereby enabling it to generate additional revenues of $87,417,000 in the Electric Department and

$26,207,000 in the Gas Department. We are of the opinion that this request is the least controversial of PG&E's three cash flow increase proposals since other energy utilities are allowed to normalize the 6% ITC for ratemaking purposes. PG&E's position, however, is somewhat dissimilar to that of the other energy utilities in that it elected the flow-through option, whereas the other utilities did not make such election. PG&E's request to ratably flow-through the 6% portion of the ITC has been superseded by the requirements of the Tax Act which will be discussed in subsequent paragraphs.

Incremental Depreciation

The third PG&E proposal to improve cash flow is to allow more rapid ratemaking depreciation on electric production plant. PG&E justifies this proposal as recognizing marginal cost principles in depreciation calculations which would help set a level of depreciation expense for revenue requirements that would support the Commission's strongly expressed objective of conservation. The allowance for incremental depreciation could provide $161,053,000 of additional depreciation expense in 1982, although PG&E restricted its request for incremental depreciation to $70 million for 1982 to produce a revenue requirement of $144.5 million for this proposal. We are not convinced that we should at this time abandon our past practice of permitting a utility to recover the cost of plant investment over the used and useful life of such assets. Under this concept ratepayers are required to bear their proportionate share of the cost of any plant investments made to provide service to such customers.

The three cash flow proposals by PG&E are estimated to increase revenue requirements in 1982 by approximately $323 million for the Electric Department and $26 million for the Gas Department and cash flow for the combined departments of approximately $169 million. Is there a need for adoption of PG&E's cash flow proposals?

PG&E has stated that the purpose of the cash flow proposals was to reduce its financing requirements by at least one security offering each year. It appears that this goal has been achieved by a change in its resource plan as shown in Tables 5 and 7 of Exhibit 26. Furthermore, we are of the opinion that when Diablo comes on stream and contributes earnings and cash flow, many of the problems which have contributed to PG&E's financial problems in the last several years will be alleviated. We are not convinced that adoption of PG&E's NEAR and incremental depreciation proposals are warranted.

Tax Act

Subsequent to the conclusion of hearings in July 1981, the Tax Act was signed into law. The Commission reopened hearings in Order Instituting Investigation (OII) 24 to consider the impact of the Tax Act on utilities. The hearings in OII 24 revealed that it would be necessary to reopen the record in this proceeding to obtain evidence on the impact of the new Tax Act on the results of operations for PG&E for test year 1982 and attrition year 1983, including the impact on rate of return resulting from increased cash flow as a consequence of the operation of the new Tax Act.

PG&E contends that under the Tax Act the Commission must implement normalization of the ACRS deductions and ITC on post-1980 assets for ratemaking purposes if PG&E is allowed to retain these benefits. Under normalization the accumulated deferred ITC and accumulated deferred income taxes resulting from ACRS will both be deducted from the rate base on which PG&E is allowed to earn a return. PG&E also contends that the repair allowance provision is no longer available under the Tax Act.

At the reopened hearings on November 9 and 10, 1981, PG&E's witness R. Cuneo testified on the impact of the Tax Act on the results of operations for test year 1982 and attrition year 1983 and witness Doudiet testified on the impact of the Tax Act on the cost of equity capital under full normalization of ITC and depreciation as mandated by the Tax Act. Witness Cuneo testified that the Tax Act made the following changes in the tax laws affecting public utilities:

1. The adopted ACRS provides for more rapid tax depreciation of plant and equipment added in 1981 and subsequent years.
2. Eliminated the repair allowance deduction.
3. Made minor changes in the ITC law.
4. Provides for a research and experimentation (R&E) tax credit.
5. Requires normalization of the tax benefits of ACRS as well as ITC, otherwise the utility is limited to straight line depreciation and loses the ITC.
6. Under the transition rule the normalization requirements are triggered by the first rate order issued after the passage of the Tax Act.

PG&E presented data on the additional revenue requirements necessary due to the passage of the Tax Act over the amounts shown in Exhibits 179 and 180, the comparison exhibits for test year 1982 for the Electric and Gas Departments. PG&E developed data based on three different scenarios: PG&E normalization position, full flow-through, and the Average Annual Adjustment (AAA) method and Annual Adjustment (AA) method of normalization adopted by the Commission in D.87838 for The Pacific Telephone and Telegraph Company. Under PG&E's normalization position the revenue requirements for the Electric and Gas Departments are increased by $84,070,000 and $21,476,000, respectively, for a total increase of $105,546,000 over and above the amounts shown in the comparison exhibits. PG&E's normalization position reflects the elimination of the repair allowance, ratably flows through the deferred ITC as of December 31, 1980, of $27,100,000 over 26 years, flows through the

1981 ITC to ratepayers and stockholders, treats the 1982 ITC as a rate base reduction, and normalizes the tax benefits of Accelerated Cost Recovery System (ACRS). Over and above the $105 million additional revenue requirement previously discussed, witness Cuneo explained that PG&E's initial cash flow proposal to ratably flow through the 6% portion of the ITC already provided revenue requirements of about $99 million, of which approximately $77 million related to partial normalization of ITC on 1982 property. Therefore, the revenue requirement effect of the Tax Act on 1982 results of operations was stated to be $77 million plus $105 million or approximately $182 million.

Under full flow-through it is assumed that the Commission will impute flowing through the tax benefits of ITC and ACRS depreciation for ratemaking purposes. The resulting loss of these tax benefits and the loss of the repair allowance was calculated to increase revenue requirements for the Electric and Gas Departments for test year 1982 by $72,998,000 and $17,823,000, respectively, or a total of $90,821,000. The deferred ITC as of December 31, 1980, of $27,100,000 is flowed through in 1982 and 1983. Although full flow-through would appear to be more favorable compared to full normalization in 1982, witness Cuneo stated that this was misleading in that it fails to recognize the rapid buildup in the deferred tax reserve used as a rate base deduction in the ensuing year and the permanent loss of ITC. The additional revenue requirements in the attrition year under PG&E normalization are $30,363,000 and $5,095,000 for the Electric and Gas Departments, respectively, and the comparable additional revenue requirements in the attrition year are $51,620,000 and $11,537,000 for the Electric and Gas Departments under full flow-through.

Under the AAA/AA normalization method, the additional revenue requirements for the Electric and Gas Departments for test year 1982 were calculated to be $71,038,000 and $16,547,000, respectively. For attrition year 1983 the additional revenue requirements are estimated to be $26,107,000 and $3,279,000 for the

Electric and Gas Departments. The AAA/AA method of normalization produces a lower revenue requirement figure than under full normalization since it uses a four-year average forecast of the deferred tax reserve as a rate base deduction. The AAA/AA normalization methodology has been challenged by the Internal Revenue Service. PG&E recommends the adoption of its full normalization position because it provides the best protection against possible Internal Revenue Service challenges to, and the possible loss of, eligibility for ACRS and ITC under the Tax Act.

Witness Doudiet testified that if the Commission sets revenue requirements in PG&E's test year 1982 general rate case, based on fully normalized ITC and depreciation for new plant additions, it should have the effect of lowering the cost of equity capital to PG&E because normalization improves cash flow. He estimated that a reduction in the cost of equity capital in the range of 25 to 75 basis points would occur if cash flow improvements in the full amount originally requested were granted. ($359 million in additional revenue requirements for PG&E's original cash flow proposals were estimated to produce approximately $174 million in additional cash flow.) Since PG&E's original cash flow proposal relating to ratable flow-through of a portion of the ITC was superseded by the normalization of the Tax Act, the total revenue requirements resulting from the NEAR proposal, incremental depreciation, and changes mandated by the Tax Act would be approximately $450 million. In addition, while Diablo investment and operating costs were not an issue in this proceeding, the record indicates that if Diablo 1 and 2 were to go into service in 1982, PG&E's revenue requirements could roughly increase by approximately $262 million[1/] and its cash flow by roughly $131 million because of the normalization requirement of the Tax Act.

1/ Assumes half-year operation and half-year ACRS over straightline depreciation and one-year flow-through of ITC against option 1, normalization of ITC.

Witness Doudiet proceeded to explain that these cash flow improvements would still have the effect of reducing the cost of equity in the same range of 25 to 75 basis points used when he testified relating to PG&E's original cash flow improvement proposals. The witness stated that although it is difficult to accurately measure the cost of equity capital, it is possible to measure debt costs, and for certain purposes, changes in debt costs can be a reasonably adequate proxy for the cost of equity. With the additional cash flow resulting from PG&E's three cash flow proposals, the witness believes that PG&E's debt will once again be looked upon in the marketplace as a true double-A-rated debt offering rather than the single A rating at which it now trades. Such an improvement in the quality of its debt would result in a 25 to 75 basis point improvement in its debt cost and, therefore, it was witness Doudiet's opinion that it would not be unreasonable to assume a similar reduction in the cost of equity. Doudiet further stated that while the additional cash flow improvements resulting from the Tax Act, including Diablo or other sources, would have a positive effect, he did not see that such improvements would enable PG&E to move toward a triple A rating. Therefore, it was the witness' opinion that his range of 25 to 75 basis point improvement in the cost of equity would remain unchanged. Doudiet further testified that in considering any adjustment in the cost of equity, it was essential that such reduction in cost of equity be considered only after a base equity cost has been determined which would accurately reflect true market conditions as well as ensuring financial health.

The staff also presented witnesses R. Joshi and C. Conner to testify on the effects of the Tax Act on test year 1982 and attrition year 1983. Joshi testified on the R&E tax credit. Joshi took exception to PG&E's proposal to defer recognition of R&E tax credit until the next general rate proceeding and estimated that a

$1,800,000 credit for the Electric Department and a $115,000 credit for the Gas Department should be adopted for the purpose of this proceeding. The witness had no objection to the establishment of a balancing account if the actual credits were greater or less than the adopted estimate to be adjusted in the next general rate case.

Witness Conner presented a summary of revenue requirement changes resulting from the Tax Act for test year 1982 and attrition year 1983. The three methods used are the full normalization, AAA/AA normalization, and full flow-through. The staff's additional revenue requirement figures differ from PG&E's estimates under full normalization because of differences in the estimates of repair allowances, adjustment for lower interest expenses because of lower financing requirements, the current recognition of a R&E tax credit, and difference in the treatment of ITC.

Staff witness Conner recommends that the Commission adopt full normalization of ACRS and ITC in this proceeding in order to comply with the requirements of the Tax Act. She also supported staff witness J. Pretti's position in OII 24 that the AAA/AA methods of normalization previously adopted by the Commission are no longer appropriate in that the Regulatory Lag Plan provides that general rate cases for major utilities be conducted every two years with an attrition adjustment made in the year following the test year. Thus, full normalization under the Regulatory Lag Plan, plus step rates for the attrition year incorporate the features and goals of the AAA/AA methods in that test year estimates of the deferred tax accounts and tax expense can be reflected in test year rates, and the estimated growth in deferred taxes and resulting tax expense can be recognized in the attrition year rates. The ratemaking treatment, therefore, will be on an annual basis.

The staff figures, under a full flow-through scenario, differ substantially from PG&E's calculations since the staff based its calculations on the assumption that PG&E would receive the tax benefits of ACRS and ITC even though it would lose these benefits if the Commission flowed them through to the ratepayers.

The decision in OII 24 addresses the general policy issues relating to the appropriate ratemaking treatment to be adopted as a consequence of the operation of the Tax Act; therefore, we will not repeat such discussion in this order. The decision in OII 24 establishes that full normalization of ACRS and ITC benefits will be adopted for ratemaking purposes. There are, however, certain issues that have not been addressed in that decision and these issues are deferred to the individual rate cases.

The first issue is the appropriate ratemaking treatment for the deferred ITC as of December 31, 1980. The balance as of December 31, 1980, of approximately $27 million results from the Commission's averaging method used for flowing through ITC and does not reflect any amount which would be affected by the Tax Act. PG&E requests that this deferred balance be ratably flowed through over the estimated useful life of the assets, whereas the staff recommends that the balance be flowed through to the ratepayers in 1982 and 1983. Since this balance resulted from the averaging method previously used in estimating ITC for ratemaking purposes, we agree with the staff that the proper method of disposing of this balance is to flow it through to the ratepayers equally in 1982 and 1983. With respect to the 1981 ITC, we will adopt PG&E's recommendation to flow the entire amount to ratepayers and stockholders. Since rates for 1981 are already set using the flow-through treatment of ITC, the bulk of the ITC generated in 1981 is being flowed through to the ratepayers. We will permit PG&E to flow through the difference between ratemaking ITC and actual ITC to the stockholders in partial recognition of the loss of the repair allowance for 1981.

Another issue which must be resolved in this proceeding is whether to recognize an estimated R&E tax credit in setting rates for test year 1982 or to defer recognition of such credit and require PG&E to flow through the benefits actually earned in the next general rate case. While PG&E argues that the amount of the credit is still uncertain, we believe that the staff estimate is a reasonable estimate to adopt for the purposes of this proceeding.

Although there is some possibility that the repair allowance may be resurrected in part or in whole, we do not see anything definitive in the immediate future. We will, therefore, consider such repair allowance to be lost for the purpose of this proceeding. If it becomes apparent that the repair allowance will once again be available, the Commission can take the necessary measures to adjust rates at that time.

The final issue which must be resolved in this proceeding is to consider the impact on rate of return resulting from the improvement in cash flow as a consequence of the Tax Act. The record in this proceeding indicates that PG&E's revenue requirements will increase approximately $180 million and its cash flow by approximately $88 million because of the Tax Act. These amounts are exclusive of any benefits that may result when Diablo and other major production plants become operational. PG&E estimates that should Diablo become operational in 1982, its revenue requirements could increase by $262 million and its cash flow by $131 million. While the figures for Diablo are considered rough approximations, it is obvious that the Tax Act, through its ACRS and ITC normalization requirements, will generate substantial cash flow to PG&E when such plants become operational. In arriving at our adopted rate of return for PG&E we will give consideration to the changes both in revenue requirements and in cash flow resulting from the Tax Act.

Energy Commission's
Incentive Proposals

The Energy Commission has presented an innovative proposal for a system of incentives to direct PG&E's management to invest in preferred resources or procure contracts for preferred resources. While we do not believe that the proposal has been fully enough developed to allow its adoption in this case, we place the staff and utilities on notice that we intend to study the various ramifications of such an incentive system in a future proceeding.

This Commission has stated in prior decisions that our energy utilities should promote conservation and alternative energy resources in meeting the energy needs of the 1980s. We are firmly convinced that our language in D.84902 and 91107, cited below, hold equally true today.

> "To this end, we intend to make the vigor, imagination, and effectiveness of a utility's conservation efforts a key question in future rate proceedings and decisions on supply authorization. . . . The effort we expect is not limited to exhortation, advertising, and traditional means for promoting conservation. We expect utilities to explore all possible cost-effective means of conservation.
>
> "Similarly, we expect utilities to work aggressively for the development of alternate energy sources, including solar and geothermal energy, and we will consider these efforts in rate and supply decisions. (PUC Dec. 84902, Sept. 16, 1975, cited in Dec. 91107, p. 151.)
>
> "We believe that it is important that we reiterate the commitment of this body to the promotion of energy conservation and the use of alternative energy resources. Where the marginal cost of conserved energy is less than the marginal cost of new supply, the

> former should always be the investment of choice. Supply from nonconventional and renewable sources, where it costs less at the margin than supply from conventional sources, should be the preference. We expect the energy utilities we regulate to make these principles central in their planning and investment decisions. . . . In establishing specific goals, PG&E should be guided by the following overall goal: All currently cost-effective conservation potential shall be achieved to the level of effective market saturation by 1985. This is ten full years since the Commission stated its intention to make the vigor, imagination, and effectiveness of a utility's conservation efforts a key question in future rate proceedings and decision and supply authorization." (D.91107, PG&E's last general rate case, December 19, 1979, pp. 152, 205.)

The Energy Commission and certain other parties presented evidence that PG&E's progress in developing alternative energy resources has been less than satisfactory and that PG&E's management needs proper incentives that will direct PG&E in accelerating development of shorter lead time conservation and alternative energy resources. We agree strongly that PG&E must be more aggressive in its promotion of alternative energy resources.

No one should be more keenly aware than PG&E itself of the financing problems associated with the development of long-lead time power plants. And PG&E surely understands this Commission's continuing commitment to conservation and development of alternative energy resources.

However, the establishment of a system of incentives and penalties, such as that proposed by the Energy Commission, may well provide needed additional motivation to our utilities for the aggressive promotion of alternative resources. Therefore, we intend to pursue this concept in a generic proceeding in the near future.

Adopted Rate of Return

After weighing the evidence in this proceeding, we are of the opinion that a rate of return on rate base of 12.20% for 1982 and 12.57% for attrition year 1983, providing a 16% return on common equity is reasonable and will enable PG&E to attract the necessary capital to provide reasonable service at reasonable rates to its customers. Such rate of return will provide a times interest coverage after taxes of approximately 2.8 times, which we believe will enable PG&E to trade at an AA bond rating. Table III-5 sets forth the adopted rate of return which assumes that all new long-term debt for 1982 will sell at an interest cost of 15% and preferred stock at a dividend rate of 14.75%. For 1983 we have assumed that all new debt will sell at a 14% interest rate and preferred stock at a 13.75% dividend rate.

In addition to the adopted rate of return, we have provided for an electric revenue adjustment mechanism to eliminate any controversy of estimating electric sales in test year 1982 and in attrition year 1983 and also to eliminate any disincentives for PG&E to push its conservation efforts. We are also adopting step rates for 1983 and an indexing mechanism in adjusting rates for the attrition year. While we would ordinarily not be receptive to the use of an indexing mechanism under normal conditions, we find that such mechanism is essential at this time to enable PG&E a reasonable opportunity to earn the authorized rate of return and also protect the ratepayers from possible overestimates of expenses. Our experience in the past two years has clearly shown that in times of rampant inflation and unstable interest costs, it is impossible to make reasonable estimates of costs 12 to 18 months in the future. The details of our attrition rate adjustment mechanism with indexing will be covered on subsequent pages.

Table III-5

PACIFIC GAS AND ELECTRIC COMPANY

Adopted Rate of Return
Test Year 1982
Attrition Year 1983

Component	Capital Ratio	Cost Factors	Weighted Cost
Average Year 1982			
Long-Term Debt	45%	9.73[a]	4.38%
Preferred Stock	14	9.03[a]	1.26
Common Stock Equity	41	16.00	6.56
Total	100%		12.20%
Average Year 1983			
Long-Term Debt	45%	10.42[a,b]	4.69%
Preferred Stock	14	9.46[a,b]	1.32
Common Stock	41	16.00	6.56
Total	100%		12.57%

a - Assumes long-term debt cost of 15% and preferred stock cost of 14.75% in 1982 and actual 1981 debt and preferred stock costs.

b - Assumes long-term debt cost of 14% and preferred stock cost of 13.75% in 1983.

While we have rejected adoption of PG&E's various cash flow proposals, the Tax Act has legislatively provided PG&E with a substantial increase in cash flow. Our adopted rate of return on rate base and return on common equity gives consideration to this increase in cash flow as well as the adoption of ERAM and attrition adjustment procedures.

AER Rate Adjustment

In D.93628 the Commission adjusted electric base rates to exclude fuel oil inventory as a base rate item and permitted the recovery of carrying costs associated with fuel oil inventory in the AER rate. D.93628 also provides that the AER rate be revised whenever the Commission adopts a change in the authorized rate of return. Since we have adopted a 12.20% rate of return in this order, it is appropriate to revise the AER rate to reflect this change in rate of return. The AER rate will be revised from .00257 $/KWh to .00276 $/KWh to produce $10,684,000 in additional AER revenues. The additional revenue requirement was calculated by multiplying the CPUC jurisdictional fuel oil inventory adopted in D.93628 of $226,097,000 by the new authorized rate of return of 12.20% and by application of a 1.6849 net-to-gross multiplier.

IV. ERAM

Historically, the staff and PG&E in a rate proceeding have disagreements over the estimation of sales and revenues for a test period. In their initial exhibits in this proceeding, there was a $150 million difference in electric revenue estimates for test year 1982 and over $25 million for attrition year 1983 primarily due to differences in sales estimates. Although the two parties were able to reach a compromise sales estimate position for this proceeding, and therefore eliminate revenues as an issue, the staff, PG&E, and Energy Commission all support the concept of a revenue adjustment mechanism to assure that the utility collects the appropriate level of revenues and does not receive a windfall or suffer from inadequate revenues because of the level of sales adopted in this decision. Moreover, the establishment of a revenue adjustment mechanism is especially important to eliminate any disincentives for a utility to promote conservation and to pursue the policies enunciated by this Commission on achieving all cost-effective conservation.

PG&E, Energy Commission, and the staff all suggested an ERAM proposal (under various names). Although Energy Commission's proposal is not in sufficient detail to permit ready adoption, it was not significantly different in concept from the other proposals. In its brief Energy Commission argues for the adoption of the staff ERAM proposal with the exception of the 5% limitation for recovery of revenue shortfalls which it sees as a disincentive to conservation.

PG&E's ERAM proposal is based upon the gas SAM. Under PG&E's proposal a base amount equivalent to the Commission's jurisdictional base revenue requirement from sales determined in this proceeding is used. The ERAM would provide base revenues to PG&E as adopted by the Commission and independent of actual sales levels. Any overcollection or undercollection of revenues will flow into a balancing account and shall bear interest at the rate provided in Part B of the Preliminary Statement. Adjustments to the rates would be made at the same time ECAC revisions are made.

The staff's ERAM proposal is essentially the same as PG&E's mechanism except for two modifications. The staff recommends that the ERAM compare monthly authorized base rate revenues to the monthly recorded base rate revenues because revenue flows to PG&E vary by season of the year. The use of a revenue distribution schedule recognizes that revenues are not received equally throughout the year; therefore, adoption of such a schedule would reduce the amount of monthly debits and credits of interest and, consequently, the extent of rate fluctuations.

The staff further recommends that a 5% limitation be placed upon the magnitude of revenue shortfalls recoverable through the ERAM balancing account in any one-year period. Should the shortfall exceed the 5% limitation, PG&E would be required to file an application to justify recovery of any shortfalls in excess of 5%. There would be no limitation on any overcollections.

PG&E's witness testified that the modification included in the staff proposal for a monthly revenue distribution schedule was an unnecessary refinement at this time. He did not, however, see any problems in adopting such modification if so ordered by the Commission. PG&E believes that since ECAC rates fluctuate substantially during the year, the staff's attempt to match ERAM revenues on a monthly basis would be overshadowed by the changes in the ECAC rates.

Both PG&E and Energy Commission opposed the staff's modification to limit recovery of undercollections under ERAM not to exceed 5%. PG&E states that the avowed purpose of such a limitation is unnecessary in view of the importance PG&E placed on accurate sales forecasting for financial planning, resource planning, and for reporting to Energy Commission. Both PG&E and Energy Commission also oppose the 5% limitation as being anti-conservation in nature.

We believe the reasons now justify the establishment of an ERAM. It will reduce the time devoted to the issue of appropriate sales estimate levels to be used for ratemaking. It is especially difficult in this period to make accurate sales estimates because of the state of the economy and the inability to accurately quantify the effects of conservation which we are expecting our utilities to promote even more vigorously in the future. Furthermore, the adoption of an ERAM at this time will eliminate any disincentives PG&E may have to promote vigorous conservation measures and also be fair to ratepayers in assuring that PG&E receives no more or no less than the level of revenues intended to be earned. Our adopted ERAM is set forth in Appendix D. We will adopt the staff proposal to compare monthly authorized base rate revenues to the monthly recorded base rate revenues rather than assume that revenues will flow to the utility on an even basis throughout the year. We will, however, reject the staff's proposal to limit undercollections of base rate revenues under the ERAM to 5% as being unnecessary and contrary to our goal of eliminating disincentives for PG&E's pursuing cost-effective conservation measures.

V. Attrition Rate Adjustment (ARA) Mechanism

In this proceeding PG&E, Energy Commission, and the staff agree that an effective attrition mechanism is necessary to enable PG&E to have an opportunity to earn its authorized rate of return in the attrition year. All three parties agree that the adoption of step rates in 1983 is preferable to an attrition mechanism which inflates the return on common equity in 1982 in order to compensate for attrition in 1983.

PG&E proposed that a set of rates be adopted in this decision for attrition year 1983 and the revenue levels underlying such rates be reviewed in late 1982 and adjusted, if appropriate, prior to the rates going into effect on January 1, 1983. Under PG&E's proposal, changes in the following cost categories would be permitted:

1. Wage costs - include only changes in wage rates and labor activity from that adopted.
2. Material costs - include only changes in the nonlabor component of operation, maintenance, and administrative and general expenses excluding changes in costs reflected in Parts B through D of this Preliminary Statement.
3. New investment - include only any change in net investment resulting from increases or decreases in plant and materials and supplies in inventory.
4. Cost of capital - include only any change in the percentage cost of capital (including associated taxes) resulting from the cost of mortgage bond and preferred stock issues and from changes in capital structure resulting from any security issues made or to be made and applied to adopted net investments as may be changed below.
5. Special items - include only any impact on revenue requirement from new or revised projects, services, and the like which is in excess of $5 million annually for any included items.

PG&E's witness Gallavan testified that his attrition rate adjustment proposal, involving a review process by the Commission in the latter part of test year 1982 before establishing rates for 1983, provides the necessary flexibility so that rates can be adjusted as required in light of the conditions existing at that time. PG&E suggests that such review process could be eliminated through adoption of an indexing procedure which would allow rates to reflect unanticipated changes in expenses due to increases in the general price level which are beyond the control of the company and which occur after the Commission decision date. PG&E recommends the use of Gross National Product (GNP) deflator or the Wholesale Price Index (WPI) for industrial commodities as appropriate indices. Witness Gallavan further proposes that the Commission should recognize the current volatility of the economy by increasing the index used for ratemaking purposes by an amount, for example, of three percentage points. Should the actual escalation rate be less, a refund with interest would be made.

Energy Commission's witness Marcus testified that financial attrition, operational attrition, and attrition of earnings resulting from conservation below the adopted demand forecast all result in reduced earnings between rate cases. Attempts by PG&E and the staff to project rates to be effective in 1983 on the basis of today's projection of future inflation and future interest rates is not good practice as demonstrated by PG&E's experience in the last general rate case and also in Southern California Edison Company's general rate case. Conversely, if the inflation rates should fall faster than predicted by PG&E and the staff, PG&E could earn excess profits. In view of these uncertainties, witness Marcus recommends that limited hearings similar to the emergency rate relief proceedings held in A.59902 be scheduled before January 1983 rates are established to take into consideration the actual conditions existing at that time. The other option would be full or partial indexing. Energy Commission also recommends that due to the goals set by the Commission and Energy Commission, utility conservation expenses are rising more rapidly than the rate of inflation; therefore, expenses related to preferred resources, load management, and conservation should be permitted to be recovered in full.

Staff witness DeBerry proposed the adoption of a fixed set of attrition rates for 1983 similar to that developed by PG&E by using the test year 1982 as a base for projecting 1983 expenses. The staff's revised attrition allowance for 1983 as shown in Exhibit 185 was $86.6 million for the Electric Department and $42.5 million for the Gas Department, or a total of $129.1 million. This compares with PG&E's revised attrition allowance estimate of $144.2 million for the Electric Department and $108.9 million for the Gas Department, or a total of $253.1 million. These figures do not reflect the effect of the Tax Act, and, in the case of PG&E, the 18% return on common equity requested in its opening brief.

The staff proposal differs from PG&E and Energy Commission's proposals in that it opposes a second look procedure because of the staff's limited manpower and the caseload confronting the staff. The staff further opposes the review procedure since it could well result in a delay in the granting of the attrition rate relief to which PG&E is entitled, and, secondly, such a procedure would seriously dissipate PG&E's incentive to control operating expenses in the test year. Table V-1 compares the attrition allowance estimate of the staff and PG&E, not including the Tax Act effects.

Table V-1

PACIFIC GAS AND ELECTRIC COMPANY

Comparison of Company and Staff*
Attrition Estimates for 1983
CPUC Jurisdictional
Revenue Requirements Basis
($000)

	Staff Revised (A)	Utility Revised (B)	Utility Exceeds Staff Revised (C=B-A)
Electric Operations			
Revenue	$ (46,892)	$ (46,892)	$ -
Labor (Wages Only) 1/	27,194	37,931	10,737
Nonlabor 2/	34,084	52,024	17,940
ITC 3/	(15,157)	-	15,157
Rate Base 4/	68,917	79,484	10,567
Subtotal (Operational Attrition)	68,146	122,547	54,401
Financial Attrition 5/	18,417	21,697	3,280
Total	86,563	144,244	57,681
Gas Operations			
Labor (Wages Only) 1/	14,268	16,674	2,406
Nonlabor 2/	11,470	16,298	4,828
ITC 3/	(3,306)	-	3,306
Rate Base 4/	14,352	68,255	53,903
Subtotal (Operational Attrition)	36,784	101,227	64,443
Financial Attrition 5/	5,675	7,684	2,009
Total	42,459	108,911	66,452

1/ Difference due to different 1982 "base" labor expenses and staff elimination of activity growth in 1983.

2/ Difference due to different 1982 "base" nonlabor expense, different 1983 escalation factors and staff elimination of activity growth in 1983. Electric Department also reflects change in treatment of DWR fuel costs (Ex. 54). Nonlabor expense includes pensions and benefits and payroll taxes escalated at the labor escalation rate.

3/ Staff includes credit for ITC not included by Company.

4/ Difference due to differing estimate of rate base growth and proposed rates of return on rate base.

5/ Difference due to different 1983 estimates of rate base.

*The numbers in this table were calculated prior to enactment of the Tax Act. The table also does not reflect the revised labor escalation rate shown in Exhibits 179a and 180a.

Of the $124.1 million difference in the two attrition estimates for 1983, $64.5 million is attributable to differences in rate base estimates and proposed rates of return, $13.1 million in labor expenses, $22.8 million in nonlabor expenses, $18.4 million for ITC not considered by PG&E, and $5.3 million in financial attrition due to differences in 1983 estimates of rate base.

The labor cost differences result from the difference in 1983 base year labor cost estimates between PG&E and the staff and also to PG&E's use of a 2.1% increase in the Electric Department and a .89% increase in the Gas Department estimates for increased activity levels. The staff omitted any increase for activity growth on the assumption that productivity increases would offset any increased costs. PG&E contends that the staff failed to ascertain the extent to which assumed productivity increases would offset increased costs resulting from growth in activity levels. Furthermore, since historical data were used in the forecasting of costs, PG&E states that such data would reflect the historical productivity increases.

Nonlabor cost differences were due to the staff's adoption of lower nonlabor escalation factors, the application of such factors on a lower base, and the staff's assumption that productivity increases will offset activity growth in nonlabor costs of 3.47% and 1.2% for the Electric and Gas Departments, respectively.

Attrition year rate base differences between PG&E and the staff result from the staff's use of a five-year average of net additions to plant in constant 1979 dollars per customer to determine 1983 additions to rate base and to the differences in proposed rate of return. PG&E argues that its estimate is superior since it reviewed all planned additions to plant in 1983, while the staff methodology assumes that all rate base additions are solely the function of new customers and no consideration is made for replacement of plant for the use of existing customers. The staff believes that a great deal of uncertainty exists in estimating events occurring two years into the future. Although PG&E may attempt to thoroughly review its planned capital expenditures in arriving at its estimate, the staff believes such methodology is not necessarily superior because of the impermanence of resource plans on which projections are based. The staff advocates adoption of its methodology since it is based on historical data and since it is practical and does not burden limited staff resources.

Although the treatment of ITC was another area of difference between staff's and PG&E's attrition allowance estimates, the Tax Act will require full normalization if PG&E is to retain such tax benefits. Our adopted treatment of ITC and ACRS will be consistent with the requirements of the Tax Act.

The difference in the allowance for financial attrition between staff and PG&E is primarily due to differences in the estimates of 1983 rate base. Our adopted financial attrition allowance will be developed from our adopted rates of return for 1982 and 1983 of 12.20% and 12.57%, respectively.

Summary

Our adopted ARA mechanism for 1982 will not consider the change in sales and revenue estimates for 1982 since our adoption of the ERAM procedure will automatically adjust for increased revenues. Our labor and nonlabor costs adopted for test year 1982 will be escalated by appropriate inflation factors for labor and nonlabor expenses which will be discussed in the subsequent paragraphs on indexing. We will not adopt a growth factor but assume that any growth or increase in activity levels will be offset by increased productivity and efficiency. While we believe a full attrition year review of rate base items is the most accurate way of estimating 1983 rate base, we are aware of the staffing and caseload problems of the staff and believe the staff's methodology is the most practical.

Indexing

The staff takes a neutral position to PG&E and Energy Commission's suggestion that indexing be considered if the Commission is reluctant to adopt a review process recommended by both parties late in test year 1982. The staff did, however, offer an indexing procedure should the Commission decide to adopt such a procedure for the attrition year in this proceeding. Under the staff's proposal, the labor components of the attrition allowance would be indexed by taking the labor expense in 1982 and increasing such amount by 3% plus 74% of the CPI increase between August 31, 1981, and August 31, 1982, which would approximate PG&E's wage increase between test year 1982 and attrition year 1983. The nonlabor expenses would be increased by the latest forecast of an applicable inflation index which the staff described as a modified Producers Price Index (PPI) (modified to eliminate those items not appropriate to utility operations). The staff recommends the use of the Data Resources, Incorporated (DRI) forecast, which is published monthly and includes projections into the attrition year. Should the actual nonlabor inflation rate exceed the adopted nonlabor inflation rate for 1982, the staff recommends that the base should be corrected in determining the estimated nonlabor expenses for 1983. This procedure is intended to correct any errors made in estimating the inflation rate for 1982 as it would affect the attrition year.

The staff's indexing proposal would have PG&E submit an advice letter in October 1982 showing nine months' recorded and three months' estimated results of operations for the test year. If, after review, it is determined PG&E would not exceed its allowed rate of return plus 20 basis points in the test year, the staff would recommend that the full attrition increase be granted. If the recorded rate of return exceeds the 20 basis point margin, the staff recommends that such excess revenues should be included in the advice letter for consideration by the Commission. The staff futher recommends that a limitation be placed on the return on equity in the attrition year 1983. If the return on equity should exceed the adopted return on equity by .50%, the staff recommends that PG&E be required to apply to the Commission for disposition of these excess revenues in connection with the 1984 general rate case. Should the Commission adopt the indexing procedure, the staff further argues that it would result in a lessening of the risk for PG&E and consideration of this lower risk should be given in determining the reasonable rate of return for PG&E.

As we have indicated earlier in our discussion, we believe an attrition mechanism is a necessity in this period where the economy is unpredictable and volatile. We believe the adoption of indexing under these circumstances is a necessity to assure that PG&E will be able to recover its costs and also to protect ratepayers from possible overestimates of operating expenses.

Under our adopted ARA mechanism we will require PG&E to file an advice letter in October 1982 showing the additional revenue requirements necessary to escalate the 1982 labor expense by a labor escalation rate of 3% plus 74% of the CPI increase between August 31, 1981 and August 31, 1982, and the 1982 nonlabor expenses by the latest DRI forecast for the PPI for industrial commodities applied to the modified PPI developed by the staff. The ARA mechanism (Appendix E) will also provide for financial attrition to recognize the 37 basis point difference in rates of return we find reasonable for 1982 and 1983. The rate base, depreciation, and income tax figures to be used in computing the attrition allowance for 1983 are set forth in Appendix E. Our adopted ARA mechanism will avoid the necessity of holding further hearings since the development of the attrition allowance will be merely mechanical. We will not adopt the staff's proposal to review the return on common equity in setting an attrition allowance for 1983, since we are not establishing a floor on the return on common equity for 1983.

In addition to the rate adjustment indicated by the ARA mechanism, we shall authorize a $10 million increase in revenues for 1983 to allow continued gradual increases in the scale of PG&E's conservation programs. The reasons for this additional increment are explained in the discussion in the Conservation Section of this decision.

In accordance with the Regulatory Lag Plan, PG&E filed Exhibit 25 which indicated those portions of the staff's showing it would accept. As a result, PG&E reduced its requested electric increase by $105 million and its requested gas increase by $63 million.

VI. Results of Operations - Electric Department

This section will primarily address the results of operations of the Electric Department for test year 1982. There are, however, many issues that are common to both the Electric and Gas Departments and where such common issues arise, they will be addressed in this section and not repeated in the Gas Department Results of Operations. Although other parties participated in certain areas of the results of operations phase, only PG&E and the staff made complete showings.

Table VI-1 presents a comparison of PG&E and staff's estimates of Electric Department results of operations for test year 1982 by total department, FERC jurisdiction, and Commission jurisdiction operations. The tables included in this section and the related discussion do not reflect the effects of the Tax Act nor the slight change in the labor escalation factor shown in Exhibits 179a and 180a. The adopted results shown in Table VI-2 reflect the revised labor escalation factor as well as the effects of the Tax Act on the Electric Department's results of operations for test year 1982.

Table VI-1

Revised

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT
RESULTS OF OPERATIONS
TEST YEAR 1982

(000's Omitted)

	Total Department		
	PGandE Revised (A)	Staff Revised (B)	PGandE Exceeds Staff (C)
Gross Operating Revenues	$ 1,474,322	$ 1,474,322	$ 0
Operating Expenses:			
Energy Cost	81,186	81,186	0
Other Production	134,451	127,460	6,991
Total	215,637	208,646	6,991
Transmission	30,755	27,137	3,618
Distribution	186,020	180,779	5,241
Customer Accounts	75,805	74,088	1,717
Uncollectibles	2,207	2,207	0
Customer Service and Information	46,331	39,536	6,795
Load Management	21,061	19,539	1,522
Administrative and General	206,659	175,469	31,190
Franchise Requirements	9,077	9,077	0
Total	798,752	735,578	57,074
Escalation Adj. - Labor	1,171	1,073	98
- Non labor	(7,143)	7,745	(4,388)
Total Expenses Excluding Taxes and Depreciation	792,780	739,996	52,784
Taxes:			
Property	54,722	54,172	550
Payroll and Business	26,601	26,555	46
State Corporation Franchise	3,952	10,947	(6,995)
Federal Income	(17,604)(A)	(24,238)(A)	6,634
Total Taxes	67,671	67,436	235
Depreciation	331,641	259,094	72,547
Total Operating Expenses	1,192,092	1,066,526	125,566
Net for Return	282,230	407,796	(125,566)
Rate Base	$ 5,969,269	$ 5,507,548	$ 461,721
Rate of Return - Rate Base	4.73%	7.40%	(2.67%)
- Equity	(1.73%)	4.73%	(6.46%)

(A) Includes full investment tax credits.

Table VI-1 (Contd.)

Revised

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT
RESULTS OF OPERATIONS
TEST YEAR 1982

(000's Omitted)

	FERC Jurisdiction			CPUC Jurisdiction		
	PGandE Revised (A)	Staff Revised (B)	PGandE Exceeds Staff (C)	PGandE Revised (D)	Staff Revised (E)	PGandE Exceeds Staff (F)
Gross Operating Revenues	$ 42,789	$ 42,789	$ 0	$1,431,533	$1,431,533	$ 0
Operating Expenses:						
Energy Cost	10,835	10,835	0	70,351	70,351	0
Other Production	5,018	5,487	(469)	129,433	121,973	7,460
Total	15,853	16,322	(469)	199,784	192,324	7,460
Transmission	4,145	4,034	111	26,610	23,103	3,507
Distribution	559	559	0	185,461	180,220	5,241
Customer Accounts	9	9	0	75,796	74,079	1,717
Uncollectibles	0	0	0	2,207	2,207	0
Customer Service and Information	0	0	0	46,331	39,536	6,795
Load Management	0	0	0	21,061	19,539	1,522
Administrative and General	3,446	3,285	161	203,213	172,184	31,029
Franchise Requirements	82	62	20	9,195	9,215	(20)
Total	[illegible]	[illegible]	[illegible]	769,656	[illegible]	[illegible]
Escalation Adj. - Labor	22	14	19	1,138	1,059	79
- Non labor	(60)	[illegible]	(88)	(7,282)	[illegible]	(4,399)
Total Expenses Excluding Taxes and Depreciation	24,067	24,312	(245)	768,713	715,683	53,030
Taxes:						
Property	2,019	1,625	394	52,703	52,547	156
Payroll and Business	398	797	(399)	26,203	25,758	445
State Corporation Franchise	(149)	(35)	(114)	4,101	10,982	(6,881)
Federal Income	(1,623)	(2,228)	605	(15,981)	(77,010)	[illegible]
Total Taxes	645	159	486	67,026	67,277	(251)
Depreciation	10,093	5,973	[illegible]	[illegible]	[illegible]	69,477
Total Operating Expenses	34,805	31,445	3,360	1,157,287	1,035,081	122,206
Net for Return	7,984	11,344	(3,360)	274,246	396,452	(122,206)
Rate Base	$197,942	$186,776	$11,166	$5,771,327	$5,320,772	$450,555
Rate of Return - Rate Base	4.03%	6.07%		4.75%	7.45%	(2.70%)
- Equity				(1.68%)	4.85%	(6.53%)
Revenue Requirements Proposed				2,343,841	1,888,311	455,530
Additional Revenue Requirement				$ 912,308	$ 456,778	$ 455,530
Net to Gross Multiplier				2.064158	2.064158	0

Table VI-2

PACIFIC GAS AND ELECTRIC COMPANY

Electric Department
Adopted Summary of Earnings
Test Year 1982 at Present and Authorized Rates
(000's Omitted)

	PRESENT RATES		AUTHORIZED RATES
	Total Department	CPUC Jurisdictional	CPUC Jurisdictional
Operating Revenues	$1,435,313	$1,392,524	$2,013,060
Operating Expenses			
Production	208,747	188,041	188,041
Transmission	28,902	24,821	24,821
Distribution	182,760	182,209	182,209
Customer Accounts	76,687	76,678	77,609
Customer Service and Info.	30,608	30,608	30,608
Load Management	16,892	16,892	16,892
Admin. & General	190,777	187,333	191,106
Subtotal	735,373	706,582	711,286
Wage Adjustment	3,379	3,378	3,378
Escalation	2,001	1,987	1,987
Subtotal after Adjustment	740,753	711,947	716,651
Book Depreciation	261,108	254,081	254,081
Taxes Other Than Income	79,396	77,014	77,014
State Corp. Franchise Tax	10,557	12,133	71,253
Federal Income Tax	46,541	47,476	303,563
Total Operating Expenses	1,138,355	1,102,651	1,422,562
Net Operating Revenues	296,958	289,873	590,498
Rate Base	5,010,048	4,840,143	4,840,143
Rate of Return	5.93%	5.99%	12.20%

Escalation Factors

Both PG&E and the staff's projections for test year 1982 and attrition year 1983 operating expenses were based on assumed escalation factors for 1980, 1981, 1982, and 1983 for both labor and nonlabor costs. Labor escalation factors were assumed to be a function of PG&E's contracts with union employees, which includes a wage escalation tied to Consumer Price Index for Urban Workers (CPI-W). Although there were some differences in the initial exhibits, the revised exhibits (Exhibits 179, 179a, 180, and 180a) show that both staff and PG&E agree that the following labor escalation rates are appropriate.

1980	10.36%
1981	12.20%
1982	10.60%
1983	8.80%

With respect to nonlabor costs, although PG&E and the staff moved closer to each other in their revised showings, there were substantial differences on the appropriate escalation factors to be used in 1980-1983. The problem with nonlabor escalation factors is whether any single index or group of indices accurately reflects the costs experienced by PG&E. PG&E uses the PPI, previously the WPI, in escalating its nonlabor costs, whereas the staff initially attempted to develop an index which purported to more nearly reflect PG&E's costs. Near the end of the proceeding the staff provided a revised nonlabor inflation index, referred to as a "modified PPI", which eliminates such items as household furniture and appliances, agricultural machinery and equipment, and certain types of fuel such as coal which are not appropriate to PG&E's operations. The following provides a listing of categories of nonlabor items and the weights that should be applied under the staff's modified PPI:

BLS Code	Category	% Weight
CPIW	CPI-W	5.00
05	Energy	7.52
06	Chemicals	8.80
07	Rubber and Plastics	4.75
08	Lumber and Wood	4.40
09	Paper and Pulp	8.78
10	Metals	23.09
11	Machinery and Equipment	18.85
14	Transportation Equipment	12.33
	Other Industrial Commodities	6.48
	Total	100.00

PG&E has less objection to staff's modified nonlabor escalation proposal than to the initial staff proposal. PG&E, however, believes that the straightforward use of the PPI is better because (a) it eliminates unnecessary controversy over the rationale behind various weighting factors, (b) it can be applied directly without an intermediate weighting effort, (c) the development of a meaningful weighted nonlabor escalation factor should be done in a forum providing sufficient opportunity for thorough review, and (d) the PPI and the staff index were very close in terms of a line fitting the data and, therefore, the simpler PPI was adequate for the purposes of this proceeding.

The following is a comparison of staff's and PG&E's nonlabor escalation rates used in estimating nonlabor expenses:

	PG&E		Staff	
	Single Year	Accumulated	Single Year	Accumulated
1980	16.20	-	14.48	-
1981	11.20	29.21	10.01	25.94
1982	9.30	41.23	9.15	37.46
1983	9.50	54.65	9.11	49.99

PG&E's higher nonlabor escalation rates result in a $7.3 million higher test year 1982 estimate for nonlabor expenses for the Electric Department and a $2.4 million higher estimate for the Gas Department.

We believe the staff has made an earnest attempt to develop an appropriate index for the purpose of escalating nonlabor expenses, and that the proposed staff nonlabor escalation factor more accurately reflects PG&E's nonlabor costs than does the use of the PPI. We will therefore adopt, as reasonable, staff's nonlabor escalation factor since it eliminates cost items from the PPI which are not appropriate to PG&E's operations.

Revenues

The initial exhibits of the staff and PG&E showed a substantial difference in the estimate of jurisdictional electric sales and revenue for test year 1982. Although PG&E and the staff were able to reach an agreement on a compromise sales estimate, nonetheless, considerable hearing time was spent in cross-examination prior to reaching a compromise (see Table VI-3). The fact that Energy Commission, PG&E, and the staff all supported a revenue adjustment mechanism undoubtedly contributed to such agreement. As discussed in our section on ERAM, we believe that the adoption of an ERAM is necessary to eliminate the possibility of large over- or undercollections of revenues and to eliminate any disincentive for PG&E to vigorously pursue cost-effective energy conservation in the electrical sector. Since there was no disagreement between the staff and PG&E, our adopted test year revenues at present rates are those set forth in Table VI-3.

Table VI-3

Revised

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
OPERATING REVENUES
TEST YEAR 1982
(000's Omitted)

Item	PGandE Original As Filed (A)	PGandE Revised(B) (C)(D)	Staff Revised	PGandE Exceeds Staff
	(A)	(B)	(C)	(D)
CPUC JURISDICTIONAL				
RESIDENTIAL	419,163	483,751	483,751	0
SMALL LIGHT & POWER	144,835	167,248	167,248	0
MEDIUM LIGHT & POWER	290,539	333,767	333,767	0
LARGE LIGHT & POWER	222,207	257,277	257,277	0
PUBLIC AUTHORITY	6,201	9,259	9,259	0
AGRICULTURAL	85,987	88,163	88,163	0
STREET LIGHTING	24,738	25,401	25,401	0
RAILWAY	3,040	3,584	3,584	0
INTERDEPARTMENTAL	2,506	2,921	2,921	0
OTHER OPERATING REVENUE	73,659	61,277	61,277	0
TOTAL CPUC BASE REVENUE	1,272,875	1,432,648	1,432,648	0
CFA REVENUE ADJ.	-	(1,115)	(1,115)	0
TOTAL CPUC REVENUE	1,272,875	1,431,533	1,431,533	0
FERC REVENUES	34,415	42,789	42,789	0
TOTAL SYSTEM REVENUE	1,307,290	1,474,322	1,474,322	0

(A) At January 1, 1980 Base Rates
(B) At June 21, 1981 Base Rates
(C) In testimony of J. Jenkins-Stark (transcript pg. 874-875) PGandE accepted staff proposal (Exhibit 34, pg. 4-1, para. 4) to update revenue figures at a later date.
(D) Does not reflect the reduction in base rates resulting from D.93628 in A.60619. The adopted revenues at present rates shown on Table VI-2 are based on base rate revenues after D.93628 adjustments.

Production Expenses

	Total Electric Department		
	PG&E Revised	Staff Revised	Adopted
Non-ECAC/Non-FCA Energy Expenses	$81,186,000	$81,186,000	$81,186,000
Other Production Op. Expenses	73,861,000	72,471,000	70,709,000
Production Maint. Expenses	60,590,000	54,989,000	56,852,000

PG&E and the staff are in agreement concerning the cost of fuel, water, and purchased power (non-ECAC/non-Fuel Cost Adjustment (FCA) energy expenses) of $81,186,000 for total electric operations and $70,351,000 for the CPUC jurisdictional electric operations; however, they disagree on the final estimates for Other Production Operation and Maintenance Expenses. Tables VI-4 and VI-5 set forth the respective estimates of PG&E and the staff for Other Production Operation Expenses and Other Production Maintenance Expenses, respectively.

Table VI-4

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
OTHER PRODUCTION OPERATION EXPENSES
TEST YEAR 1982

(000's OMITTED)

Account No. CPUC	Account No. FERC	Description	PG&E Original As Filed (A)	PG&E Revised (B)	Staff Revised (C)	PG&E Exceeds Staff (D)
		OPERATION				
		STEAM POWER GENERATION				
500	760	SUPERVISION AND ENGINEERING	$ 2,739	$ 2,731(E)	$ 2,719	$ 12
502	762	STEAM EXPENSES	12,626	12,626	12,457	169
505	764	ELECTRIC EXPENSES	28,575	27,738(E)	25,947	791
506	765	MISCELLANEOUS STEAM POWER EXPENSES	7,190	7,169(E)	6,969	200
507	765	RENTS	8,004	8,004	8,004	0
501	769	FUEL - OTHER EXPENSES	2,416	2,416	2,352	64
		TOTAL STEAM POWER GENERATION	[illegible]	[illegible]	[illegible]	[illegible]
		NUCLEAR POWER GENERATION				
517	770	SUPERVISION AND ENGINEERING	196	175(E)	174	1
519	772	COOLANTS AND WATER	62	62	62	0
520	773	STEAM EXPENSES	417	557(E)	546	11
523	775	ELECTRIC EXPENSES	248	234(E)	234	0
524	776	MISCELLANEOUS NUCLEAR POWER EXPENSES	672	671(E)	646	25
		TOTAL NUCLEAR POWER GENERATION	[illegible]	[illegible]	[illegible]	[illegible]
		HYDRAULIC POWER GENERATION				
535	780	SUPERVISION AND ENGINEERING	1,822	1,805(E)	1,797	8
537	782	HYDRAULIC EXPENSES	2,457	2,428(E)	2,389	39
538	783	ELECTRIC EXPENSES	3,495	3,462(E)	3,445	17
539	784	MISCELLANEOUS HYDRAULIC POWER GENERATION EXPENSE	2,350	2,336(E)	2,299	37
540	785	RENTS	522	522	522	0
537	786	FISH AND WILDLIFE EXPENSES	86	86	83	3
537	787	RECREATION EXPENSES	370	370	360	10
		TOTAL HYDRAULIC POWER GENERATION	[illegible]	[illegible]	10,895	[illegible]
		OTHER POWER GENERATION				
546	790	SUPERVISION AND ENGINEERING	66	66	66	0
548	792	GENERATION EXPENSES	154	154	153	1
549	793	MISCELLANEOUS OTHER POWER GENERATION EXPENSES	149	149	147	2
		TOTAL OTHER POWER GENERATION	[illegible]	[illegible]	[illegible]	[illegible]
411.7	8511	LOSSES FROM DISPOSITION OF UTILITY PLANT	0	0		
		TOTAL OTHER PRODUCTION OPERATION EXPENSES	$ 74,611	$ 72,861	$ 72,471	$1,390
		MAINTENANCE	59,856	60,590	54,989	5,601
		TOTAL LINE 27 + LINE 28	$134,467	$134,451	$127,460	$6,991

FOOTNOTES
(E) Exhibit 25

Table VI-5

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
PRODUCTION MAINTENANCE EXPENSES
TEST YEAR 1982

(000's OMITTED)

Account No. CPUC	Account No. FPC	Description	PG&E Original as Filed (A)	PG&E Revised (B)	Staff Revised (C)	PG&E Exceeds Staff (D)
		MAINTENANCE				
		STEAM POWER GENERATION				
510	440	SUPERVISION AND ENGINEERING	$ 4,545	$ 4,699(F)	$ 4,223	$ 476
511	441	STRUCTURES	1,453	1,495(F)	1,342	153
512	442	BOILERS AND RELATED APPARATUS	12,153	12,473(F)	11,399	1,074
512	443	BOILER PLANT AUXILIARIES	7,142	7,348(F)	6,676	672
513	444	MAIN TURBOGENERATOR AND RELATED APPARATUS	12,006	12,230(F)	11,232	998
513	445	MAIN TURBOGENERATOR AUXILIARIES	7,698	7,826(F)	7,092	734
513	446	ACCESSORY ELECTRIC EQUIPMENT	1,357	1,378(F)	1,257	121
514	447	MISCELLANEOUS STEAM PLANT	2,398	2,468(F)	2,230	238
514	448	URBAN RECREATIONAL FACILITIES	1	1	1	0
		TOTAL STEAM POWER GENERATION	48,755	49,718	45,452	4,466
		NUCLEAR POWER GENERATION				
528	450	SUPERVISION AND ENGINEERING	124	132(F)	131	1
529	451	STRUCTURES	105	31(F)	31	0
530	452	REACTOR AND RELATED APPARATUS	231	0(F)	0	0
530	453	REACTOR PLANT AUXILIARIES	42	44(F)	44	0
531	454	MAIN TURBOGENERATORS AND RELATED APPARATUS	7	1(F)	1	0
531	455	MAIN TURBOGENERATOR AUXILIARIES	18	38(F)	37	1
531	456	ACCESSORY ELECTRIC EQUIPMENT	2	1(F)	1	0
532	457	MISCELLANEOUS NUCLEAR PLANT	71	57(F)	56	1
		TOTAL NUCLEAR POWER GENERATION	700	304	301	3
		HYDRAULIC POWER GENERATION				
541	460	SUPERVISION AND ENGINEERING	790	788(F)	785	3
542	461	STRUCTURES	480	480	470	10
543	462	RESERVOIRS, DAM AND WATERWAYS	4,219	4,703(F)	3,761	442
544	463	PRIME MOVERS AND GENERATORS	2,398	2,387(F)	2,157	230
545	464	ACCESSORY ELECTRIC EQUIPMENT	370	369(F)	364	5
545	465	MISCELLANEOUS HYDRAULIC PLANT	200	199(F)	196	3
545	466	ROADS, RAILROADS AND BRIDGES	497	491(F)	481	10
545	467	FISH AND WILDLIFE FACILITIES	27	29	28	1
545	468	RECREATION FACILITIES	132	132	129	3
		TOTAL HYDRAULIC POWER GENERATION	[illegible]	9,578	[illegible]	707
		OTHER POWER GENERATION				
551	470	SUPERVISION AND ENGINEERING	40	40	40	0
552	471	STRUCTURES	3	3	3	0
553	472	GENERATING AND ELECTRIC EQUIPMENT	1,118	1,118	736	382
554	473	MISCELLANEOUS OTHER POWER GENERATION PLANT	129	129	86	43
		TOTAL OTHER POWER GENERATION	1,290	1,290	865	425
		TOTAL PRODUCTION MAINTENANCE EXPENSES	$59,856	$60,490	$54,989	$5,601

FOOTNOTES
(F) Exhibit No. 25

The difference in the estimates of Other Production Operation Expenses of $1,390,000 is due to the use of different nonlabor escalation factors. Since we have previously stated that we will adopt the staff's nonlabor escalation factor, we will adopt staff's Other Production Operation Expenses for 1982, less the nuclear power generation operating expenses.

Consistent with our discussion relating to the Humboldt nuclear plant under Administrative and General Expenses, we will exclude all operations and maintenance expenses relating to the Humboldt nuclear plant from our adopted expenses. PG&E will be authorized to record these expenses in its memorandum Humboldt account and accrue AFUDC on these expenditures. The disposition of the balances in the Humboldt memorandum account will be determined when the issue of retrofitting or decommissioning the Humboldt plant is resolved.

PG&E's estimate of Other Production Maintenance Expenses exceeds the staff's estimate by $5,601,000. $1,124,000 of this difference is attributable to the lower nonlabor escalation factor used by the staff. The remaining difference is due to PG&E's estimating 130 hires for steam maintenance for the period 1980-1982, whereas the staff estimates 31 hires for 1980 only, a difference of $3,532,000; PG&E's spreading the cost of dredging the Drum Afterbay over two years instead of the five-year period used by the staff, a difference of $547,000; and PG&E's estimate of two gas turbine overhauls in 1982 and 1983 compared to the staff allowance of one overhaul, a difference of $398,000.

We do not believe that PG&E has justified its estimate for 130 new hires for steam maintenance activities for the period 1980-1982. On the other hand, we do not agree that the staff's estimate of 31 new hires for the period is reasonable even taking into account that two new geothermal plants were added in 1980, that Potrero I & II plants will be removed in 1982, and that Diablo may become operational in 1982. Considering that PG&E hired 65 additional employees in 1980 alone would justify the adoption of an estimate somewhat between the staff and PG&E estimates. We will therefore adopt, as reasonable, 81 new hires for the 1980-1982 period and allow $1,766,000 for new hires in 1982.

We agree with the staff that a longer amortization period for dredging costs relating to the Drum Afterbay is reasonable. Therefore, we will reduce PG&E's estimate by $547,000.

Although the staff does not disagree with PG&E's contention that there will be two gas turbine overhauls in 1982 and 1983, staff assumes only one overhaul in each of the years as reflecting more normal conditions. PG&E contends that the staff recommendation is not realistic in that gas turbines will be requiring their initial overhauls at the rate of two overhauls in 1982 and 1983. We believe it is essential that PG&E be allowed reasonable maintenance expenses in order to protect system reliability and safety. Our adopted maintenance expenses for production, transmission, and distribution expense categories will recognize the importance we place on proper levels of maintenance. In the long run inadequate maintenance will result in higher costs, more frequent and longer periods of outages, and safety problems. We will therefore adopt, as reasonable, an estimate somewhat higher than the amounts recommended by staff. We will require PG&E to submit a report showing for 1982 the dollars budgeted for maintenance, the dollars spent, and the status of maintenance programs on or before March 31, 1983.

Transmission Expenses

	Total Electric Department		
	PG&E Revised	Staff Revised	Adopted
Transmission Expenses	$30,755,000	$27,137,000	$28,902,000

Table VI-6 shows the revised PG&E and staff estimates of transmission operation and maintenance expenses for test year 1982. Of the $3,618,000 difference between PG&E's and staff's estimates, $348,000 was due to the difference in nonlabor escalation factors, $1,149,000 to staff disallowance of various wheeling charges, $233,000 difference in load dispatching expenses, $164,000 difference in maintenance supervision and engineering expenses, staff disallowance of $1,233,000 in deferred station equipment expenses, and $491,000 exclusion of historical and deferred 1980 pole stubbing, pole treating, tower painting, and road maintenance expenses. Our adopted estimate will be based on the staff's nonlabor escalation factors.

Table VI-6

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
TRANSMISSION EXPENSES
TEST YEAR 1982

(000's OMITTED)

Account No. CPUC	Account No. FERC	Description	PG&E Original as Filed (G)	PG&E Revised (G)	Staff Revised (G)	PG&E Exceeds Staff (G)
		OPERATION				
560	850	SUPERVISION AND ENGINEERING	$ 2,876	$ 2,876	$ 2,864	$ 12
562	851	STATION EXPENSES	8,510	8,475(G)	8,425	50
563	852	OVERHEAD LINE EXPENSES	689	689	674	15
564	853	UNDERGROUND LINE EXPENSES	71	71	70	1
565	854	TRANSMISSION OF ELECTRICITY BY OTHERS	3,620	1,891(G)	742	1,149
566	855	MISCELLANEOUS TRANSMISSION EXPENSES	921	921	910	11
567	856	RENTS	183	183	182	0
561	857	LOAD DISPATCHING	1,787	1,787	1,545	242
		TOTAL TRANSMISSION OPERATION EXPENSES	18,657	16,893	15,413	1,480
		MAINTENANCE				
568	550	SUPERVISION AND ENGINEERING	1,527	1,527	1,357	170
569	551	STRUCTURES	249	249	241	8
570	552	STATION EQUIPMENT	6,351	6,351	5,007	1,344
571	553	OVERHEAD LINES*	5,413	5,413	4,803	610
572	554	UNDERGROUND LINES	235	235	231	4
573	555	MISCELLANEOUS TRANSMISSION PLANT	87	87	85	2
		TOTAL TRANSMISSION MAINTENANCE EXPENSES	13,862	13,862	11,724	2,138
		TOTAL TRANSMISSION EXPENSES	$32,519	$30,755	$27,137	$3,618

*OVERHEAD LINES

CPUC	FERC	Description	PG&E Original as Filed	PG&E Revised	Staff Revised	PG&E Exceeds Staff
571	562	CLEAN INSULATORS AND BUSHINGS	567	567	557	10
571	563	REPLACE LINE INSULATORS	564	564	551	13
571	564	STUBBING POLES	125	125	24	101
571	565	MOVING POLES AND GUYS	49	49	48	1
571	566	POLE TREATING	92	92	4	88
571	567	EMERGENCY REPAIRS	113	113	111	2
571	568	CONDUCTOR RECONDITIONING	723	723	711	12
571	569	TEMPORARY SERVICE SET-UP WORK	139	139	137	2
571	570	OVERHAUL AND REPAIR LINE EQUIPMENT	17	17	17	0
571	571	PAINT POLES, TOWERS AND ACCESSORIES	584	584	354	230
571	572	OTHER OVERHEAD LINE MAINTENANCE	881	881	789	92
571	573	TREE TRIMMING	935	935	897	38
571	574	VEGETATION CONTROL	133	133	128	5
571	575	RIGHT-OF-WAY CLEARING	291	291	275	16
		TOTAL OVERHEAD LINES	$ 5,413	$ 5,413	$ 4,803	$ 610

FOOTNOTES
(G) Exhibit No. 25

a. Wheeling Charges

The staff in disallowing $1,149,000 of various wheeling charges argues that $690,000 represents charges for years prior to 1981 and, therefore is not proper for recovery in this proceeding. We agree with the staff that recovery of such past expenses in this proceeding is inappropriate unless the Commission had agreed to defer ruling on the ratemaking treatment of such expense. D.92496 in OII 56 permits only prospective recovery of variable wheeling charges through ECAC. The dispute with respect to the Pacific Intertie fixed wheeling charge of $278,000 and the Department of Water Resources (DWR) fixed wheeling charge of $181,000 results from a difference in estimating methodology. The staff used a 1980 figure while PG&E used a five-year average figure in estimating this widely varying charge. We believe that an estimate based on a five-year average for a fluctuating charge is more reasonable than a one-year figure. We also agree with PG&E that fixed DWR wheeling charges are properly recoverable in this proceeding. We will, therefore, not adopt the staff adjustments for these two items.

b. Load Dispatching

The $233,000 difference in load dispatching expenses was the result of the staff use of 1979 recorded expenses as a base for estimating as compared to PG&E's use of a five-year average trend. We believe that the use of a five-year average trend in estimating an account which is affected by weather conditions and showing growth is more reasonable. We do not adopt the staff's recommended adjustment.

c. Supervision and Engineering

The $164,000 difference in this account was due to the use of a five-year average by the staff as opposed to the five-year trending analysis used by PG&E in arriving at its estimate. Staff justified the use of a five-year average to be consistent with PG&E's use of a five-year average in estimating other maintenance expense accounts. PG&E uses the five-year average trend since it anticipates cost increases because of growth, and further argues that 1980 recorded expenses in this category are very close to the trended estimate. We will adopt PG&E's estimate as being more realistic for this account because it incorporates the effect of growth.

d. Maintenance of Station Equipment and Deferred Expenses

The chief area of controversy between PG&E and the staff for this account, as well as in several other maintenance accounts, is the question whether maintenance work deferred in prior years should be included as an additional cost in determining test year 1982 expenses. Staff does not disagree that PG&E has been required to defer maintenance because of cash flow problems and that such maintenance work will have to be performed to prevent equipment and system breakdowns. The staff argues that inclusion of such additional costs with normal year costs is inconsistent with the Commission's normal test year ratemaking and verges on retroactive ratemaking.

Consistent with our discussion of production maintenance expenses and the importance we place on providing adequate levels of maintenance to protect system reliability and safety, our adopted transmission maintenance expenses will be higher than the level recommended by the staff although somewhat less than requested by PG&E.

Based on the above discussion, we will increase the staff estimates by $616,000 for maintenance of substations, $76,000 for pole stubbing, $66,000 for pole treating, $112,000 for tower painting, and $39,000 for road maintenance.

Distribution Expenses

	Total Electric Department		
	PG&E Revised	Staff Revised	Adopted
Distribution Expenses	$186,020,000	$180,779,000	$182,760,000

PG&E's revised estimate of $186,020,000 exceeds the staff's estimate of $180,779,000 by $5,241,000, as shown in Table VI-7. $2,678,000 of this difference is due to the lower nonlabor escalation factor used by the staff. Other major areas of differences are in the estimates for underground line accounts of $1,240,000, deferred base maintenance expenses of $227,000, deferred 1980 nonrecurring maintenance expenses of $47,000, deferred catch-up work of $889,000, and staff deletion of PG&E's accelerated Compression Connector Program of $160,000. Our adopted estimate will adopt the staff's nonlabor escalation factors.

Table VI-7

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
DISTRIBUTION EXPENSES
TEST YEAR 1982

(000's OMITTED)

Account No. CPUC	Account No. PG&E	Description	PG&E Original as Filed (A)	PG&E Revised (B)	Staff Revised (C)	PG&E Exceeds Staff (D)
		OPERATION				
580	950	SUPERVISION AND ENGINEERING	$ 22,429	$ 22,033(I)	$ 21,940	$ 93
582	951	STATION EXPENSES	12,122	12,097(M)	12,018	79
583	952	OVERHEAD LINE EXPENSES	4,635	4,635	4,589	46
583	953	REMOVING AND RESETTING LINE TRANSFORMERS	7,646	6,455(I)	6,390	65
584	954	UNDERGROUND LINE EXPENSES	2,329	2,320	1,954	366
585	955	STREET LIGHTING AND SIGNAL SYSTEMS EXPENSES	878	878	861	17
586	956	METER EXPENSES	16,608	16,608	16,449	159
587	957	INVESTIGATING AND ADJUSTING SERVICE COMPLAINTS	7,439	7,439	7,366	73
587	958	RADIO AND TV INTERFERENCE WORK	520	520	515	5
587	959	OTHER WORK ON CUSTOMER PREMISES	227	227	226	1
588	960	DISTRIBUTION MAPS AND RECORDS	5,641	5,641	5,604	37
588	961	MISCELLANEOUS DISTRIBUTION EXPENSES	20,622	20,622	20,374	248
589	962	RENTS	219	219	219	0
		TOTAL DISTRIBUTION OPERATION EXPENSES	101,316	99,694	98,505	1,189
		MAINTENANCE				
590	650	SUPERVISION AND ENGINEERING	11,645	11,645	11,536	109
591	651	STRUCTURES	437	437	424	13
592	652	STATION EQUIPMENT	3,173	3,995	3,857	138
593	662	CLEAN INSULATORS AND BUSHINGS	461	461	454	7
593	663	REPLACE LINE INSULATORS	2,316	1,721(I)	1,689	32
593	664	STUBBING POLES	559	559	231	328
593	665	MOVING POLES AND GUYS	952	756(I)	745	11
593	666	POLE TREATING	845	845	267	578
593	667	EMERGENCY REPAIRS	1,462	1,462	1,446	16
593	668	CONDUCTOR RECONDITIONING	12,396	11,403(I)	11,149	254
593	669	TEMPORARY SERVICE SET-UP WORK	1,336	1,140(I)	1,121	19
593	670	OVERHAUL AND REPAIR LINE EQUIPMENT	1,376	1,376	1,345	31
593	671	PAINT POLES, TOWERS AND ACCESSORIES	29	29	28	1
593	672	OTHER OVERHEAD LINE MAINTENANCE	7,453	7,058(I)	6,928	130
593	673	TREE TRIMMING	21,851	21,851	20,955	896
593	674	VEGETATION CONTROL	961	961	991	(30)
593	675	RIGHT-OF-WAY CLEARING	412	412	395	17
594	654	UNDERGROUND LINES	9,879	9,879	8,908	971
595	655	LINE TRANSFORMERS	4,687	4,687	4,375	312
593	656	OVERHEAD SERVICES	2,461	2,461	2,421	40
594	657	UNDERGROUND SERVICES	721	721	599	122
596	658	STREET LIGHTING AND SIGNAL SYSTEMS	1,818	1,818	1,777	41
597	659	METERS	645	645	629	16
598	660	MISCELLANEOUS DISTRIBUTION PLANT	4	4	4	0
		TOTAL DISTRIBUTION MAINTENANCE EXPENSES	87,881	86,326	82,274	4,052
		TOTAL DISTRIBUTION EXPENSES	$189,197	$186,020	$180,779	$ 5,241

FOOTNOTES
(M) Exhibit No. 25
(I) Testimony C. Molloy Vol. 9 pg. 1100 and 1101

a. Underground Lines

We agree with PG&E that its estimate for underground line accounts based on a linear trend estimate is more accurate than an estimate based on 1979 recorded data because of the growth in activity in undergrounding lines. We will therefore reject the staff's $1,240,000 adjustment to underground lines expense.

b. Accelerated Compression Connector Program

The staff made adjustment to PG&E's maintenance expenses to delete costs and benefits relating to the Accelerated Compression Connector Program. Based on the showing in Exhibit 90, we are convinced that the program is cost-effective and, therefore, we will not adopt the staff's deletion of this program

c. Other Distribution Maintenance Expenses

Consistent with the importance we place on system reliability and safety, we will adopt, as reasonable, an estimate for distribution maintenance expenses which will be midway between the staff and PG&E estimates after adjusting for the difference in the nonlabor escalation factors.

Customer Accounts Expenses

	Total Department		
	PG&E Revised	Staff Revised	Adopted
Electric Department	$78,012,000	$76,295,000	$76,687,000
Gas Department	$63,266,000	$57,977,000	$62,275,000

PG&E's estimate of Customer Accounts Expenses for the Electric Department for test year 1982 of $78,014,000 exceeded the staff's estimate of $76,295,000 by $1,717,000. For the Gas Department PG&E's estimate of $63,266,000 exceeded the staff's estimate of $57,977,000 by $5,239,000. Aside from the difference in nonlabor escalation factors and estimating procedures, the following were the major areas of disagreement: staff disallowance of meter reading supervisors positions, PG&E's use of a 20¢ postage rate, staff's exclusion of positions for PG&E's credit counselor proposal, staff's exclusion of PG&E's additional positions in 1982 for energy theft control, and staff's disallowance of PG&E's proposal to add employees for its Performance Standards and Work Measurement Programs.

a. Meter Reading Supervisors

Initially, PG&E requested 23 positions as additional meter reading supervisors for test year 1982. The staff recommended disallowance of the additional supervisors on the ground that the present meter reading operation is already a productive unit in comparison to other utilities. PG&E reconsidered its position and decided to delay asking for these new positions until 1984. However, prior to the conclusion of hearings, PG&E resurrected its request that these 23 positions be included for test year 1982. PG&E states that the question of meter reading practices became a subject of a television broadcast resulting in a significant increase in the number of requests for rereads of meters and other meter activities. PG&E believes that the additional 23 meter reading supervisors would enable them to improve their monitoring, auditing activities, and enable PG&E to inaugurate a pilot program for the vanpool concept in the San Francisco Bay Area. While we agree that with increasing utility bills there will be greater activity in meter rereading requests, we are not convinced that there is a need for duplicating the existing supervisory functions. We are convinced that some additions to meter reading supervisors are warranted to enable PG&E to pilot its vanpooling concept as well as expand the supervisory functions to correct problems with routing, auditing, and monitoring. Therefore, we will allow 12 new positions, or 50% of the additional expenses requested.

b. Mailing Costs

Since the conclusion of hearings, the U.S. Postal Service has announced new first-class postal rates of 20¢ effective November 1, 1981. We will therefore adopt PG&E's estimate as being more representative of mailing costs for the year year since it assumed such postal increase.

c. Credit Counselors

The staff recommended disallowance of $670,000 for the hiring of additional credit counselors because such a program would duplicate services available from established public agencies. PG&E contends that customers are having difficulties paying their utility bills and need expert counseling on how to find and take advantage of potential sources of assistance. Furthermore, PG&E states that credit counselors would be able to make extended payment arrangements as well as review the conservation measures a customer may take in controlling his utility bill. We agree that the problems of paying utility bills are becoming more severe with the continuing increase in the cost of utility services. Furthermore, with the announced reduction in government services and funds, we believe that PG&E will be confronted with increased requests for extended payment arrangements. For these reasons we believe 50% of the amount requested for additional credit counselors is justified.

d. Energy Theft Reduction

While the staff does not disagree with PG&E's proposal to hire 45 management employees in 1981 to control energy theft, it does recommend that the 18 additional positions requested for 1982 be disallowed. Staff justifies its disallowance on the ground that the current energy reduction program should result in sufficient savings to pay for the 18 additional positions requested by PG&E. While we do not disagree with the staff that the Energy Theft Control Program will result in increased revenues, such revenues will flow through to the ERAM we are adopting in this proceeding; therefore, if such expenditures are warranted, they must be allowed in the test year expenses. We have heard no testimony challenging the additional positions, therefore, we will allow such costs as reasonable for test year 1982.

e. Performance Standards and
Work Measurements

PG&E requests 25 new positions for its Performance Standards and Work Measurements Program. PG&E claims that in response to the Cresap Management Audit, it has developed and is testing a new work measurement system, which is a productivity analysis program. The staff recommends that such costs be denied and recommends PG&E's development of more refined work methods, efficient tools, and avoidance of studies that require more manpower

We will include the 50% of the amount requested for such performance standards and work measurement studies in our test year 1982 costs since we believe certain reasonable costs must be incurred if greater efficiency in work performance is to be achieved.

f. Gas Department Customer Accounts Expenses

A significant portion of the difference in the Gas Department customer accounts expense estimate was due to the difference in estimating procedures, which apparently varied from that used for the Electric Department. Staff's witness testified that he has attempted to arrive at a more precise estimate of customer account expenses and therefore the resulting estimate of customer account expenses for test year 1982 for the Gas Department may have varied from the percentage relationship that existed historically between the Electric and Gas Departments for this expense category. We are not convinced by the staff's presentation and, therefore, will adopt PG&E's estimating methodology in arriving at our adopted estimate less adjustments for comparable disallowances made for the Electric Department.

Customer Services and Information
Expense (Excluding Load Management)

	Total Department		
	PG&E Revised	Staff Revised	Adopted
Electric Department	$46,331,000	$39,536,000	$28,985,000
Gas Department	$25,626,000	$21,709,000	$16,020,000

Staff's and PG&E's estimates for various conservation programs included in this expense category are discussed in the Conservation Section of this decision. Our adopted estimate for this expense category is based on that discussion.

Customer Services and Information
Expense - Load Management Operating Expenses

	Total Department		
	PG&E Revised	Staff Revised	Adopted
Electric Department	$21,061,000	$19,539,000	$16,892,000
Gas Department	$ 1,236,000	$ 646,000	$ 1,033,000

A discussion of load management operating expenses and capital expenditures is contained in the Conservation Section of this decision. Our adopted load management operating expense for the Electric and Gas Departments is based on that discussion.

Administrative and General Expenses (A&G)

	Total Department		
	PG&E Revised	Staff Revised	Adopted
Electric Department	$215,936,000	$184,746,000	$190,777,000
Gas Department	$119,317,000	$103,232,000	$106,833,000

The differences between staff and PG&E's estimates will be discussed by various functional A&G expense accounts together with our adopted results.

	PG&E	Staff
A & G Salaries - Electric	$75,049,000	$63,441,000
- Gas	$38,127,000	$32,885,000
Office Supplies & Exp. - Electric	$36,508,000	$28,848,000
- Gas	$18,906,000	$14,701,000
A & G Exp. Transferred - Electric	$39,070,000	$33,118,000
- Gas	$19,841,000	$17,034,000

a. A&G Employee Growth Factor

The basic difference in the estimate of A&G salaries was in PG&E's use of a 4.05% employee growth factor based on 1976-1979 historical data which was subsequently revised to a 4.31% growth factor after inclusion of 1980 data. The staff, on the other hand, used a judgmental employee growth factor of 1%. Among the factors considered by the staff in arriving at its 1% growth rate are:

1. Salaries of 40 employees of the Energy Conservation Department have not been charged to administrative and general since 1980.

2. 40 employees of the newly created Nuclear Division are not included because D.91107 ordered PG&E to exclude all expenses related to Humboldt except some operation and maintenance expenses for ratemaking.

3. 40 additional employees of the newly created Revenue Requirements Division are not included because PG&E failed to justify their inclusion.

4. No growth or limited growth in production, transmission, distribution expenses, and rate base.

5. PG&E has currently instituted a hiring freeze.

It was assumed that all expected growth in the Computer Division and the Energy Conservation and Research Development and Demonstration (RD&D) Departments not included elsewhere will be provided by the 1% average wage adjusted growth.

We believe that PG&E's employee growth factor of 4.05% based on 1976-1979 historical data as well as the 4.31% growth factor after inclusion of 1980 data are both excessive. We are of the opinion that the 1% growth factor used by the staff is realistic, providing for reasonable growth in administrative personnel in view of the 1980 recorded experience.

b. Humboldt Plant Expenses

The staff further disallowed the expenses of 40 employees in the Nuclear Department which are charged to A&G expenses for expenses related to the Humboldt Nuclear Power Plant (Humboldt). In recommending the disallowance of $1,094,000 relating to these employees, the staff does not object to inclusion of such expenses in a deferred account to be considered for recovery when the question of recovery of Humboldt costs becomes an issue. PG&E argues that D.91107 did not order PG&E to exclude all expenses related to Humboldt and only ordered that all capital costs associated with the Humboldt facility be placed in a memorandum account. PG&E further argues that even if the staff was correct in its interpretation of D.91107, the staff was in error in its disallowance since PG&E does not employ 40 A&G personnel associated with the operation of Humboldt. Furthermore, since the Nuclear Power Generation Department was formed in 1980, such costs did not exist in the 1979 base figures used by the staff witness when he made his estimate and disallowance.

The staff also disallowed insurance costs for Humboldt and recommended that such costs, as well as any A&G Nuclear Department salaries resulting to Humboldt, be placed in a memorandum account pending the ultimate decision on the future of Humboldt. The staff accounting witness further recommended that the capital expenditures relating to Humboldt be transferred to a deferred debit account and to suspend AFUDC accruals on such balances.

Two years have elapsed since the issurance of D.91107 at which time we expressed our concerns with the future commercial potential of Humboldt. At that time we stated, "We caution, however, that any additional capital expenditures on Humboldt will be viewed by this Commission critically, and will be made entirely at the company's risk." While we are concerned with the continuing delay in resolving the operating status of Humboldt, we do not believe the staff proposal to discontinue AFUDC on Humboldt is reasonable in that it prejudges our decision on the future ratemaking treatment to be accorded Humboldt. The resolution of the future status of Humboldt should be determined in a separate proceeding. Should such proceeding prove that it is feasible to continue the necessary modifications to reopen Humboldt, then such AFUDC is a proper cost. If it is determined not feasible, the Commission has the right to make its determination as to allow or disallow such carrying costs based on the record that will be developed in such proceeding.

We will disallow all operating and maintenance expenses for Humboldt including insurance expenses for current recovery and require PG&E to record operating, maintenance, and insurance expenses for Humboldt in the Humboldt memorandum account together with the capital expenditures relating to Humboldt and to accrue AFUDC on the total. We place PG&E on notice that we expect the question of backfitting or decommissioning of Humboldt to be resolved before the next NOI is filed.

We will adopt the staff's recommended disallowance of 40 A&G Nuclear Department employees in this proceeding but not for the reasons stated by the staff. While only a small portion of the Nuclear Department's workload may be related to Humboldt, a substantial portion is related to Diablo. In view of the indefinite operating date for Diablo and our treatment of Humboldt expenses in this proceeding, we believe it is proper to exclude the 40 A&G Nuclear Department employees. It will be appropriate for PG&E to seek recovery of any Nuclear Department A&G expenses relating to Diablo in the Diablo offset proceedings in A.58911 and 58912.

c. Engineering Trainees

Another area of controversy concerned the estimated level of engineering trainees for the test year. The staff estimated 73 trainees based on an average of the 1978-1979 level of trainees, PG&E estimated 200 engineering trainees. We are of the opinion that both estimates are unreasonable and will adopt a level of 124 positions as reasonable and a disallowance of $232,000. Related to this adjustment is a $95,000 reduction in office supplies and expenses. For the Gas Department there is a corresponding reduction of $118,000 in salaries and $49,000 in office supplies and expenses.

d. Outside Services

The difference in this account results from PG&E's use of seven months recorded data for basing its estimate as opposed to a 1978 recorded figure used by the staff. The staff argues that 1980 had many nonrecurring expenses and therefore concluded that an estimate based on 1980 recorded data would be excessive. PG&E argues that the nature of outside services vary depending on company requirements, internal staffing, and funding limitations. While we agree that outside services may vary from year-to-year, we do not view 1980 as a typical year. On the other hand, an estimate based on 1978 data appears to be equally unrealistic. We will, therefore, adopt a total estimate of $5 million as reasonable for the Electric and Gas Departments.

e. Injuries and Damages

The staff estimate for this expense category was based on 1975-1978 data because the 1979 data evidenced an abnormal rate of increase over historic levels. We do not consider the staff's rejection of 1979 as reasonable and, therefore, we will adopt an estimate midway between the staff and PG&E estimates as more representative of expected expense levels for injuries and damages for test year 1982.

f. Employee Pension and Benefits

Staff and PG&E disagreed on the level of pension and benefits to be allowed for ratemaking purposes for test year 1982. PG&E's estimates were based on the most recent collective bargaining agreement negotiated by PG&E and its union employees. Staff witness disallowed certain benefits because he believed that the growth in pensions and benefits expenses have been increasing excessively and faster than labor costs as a whole. The recommended staff disallowances and reasons are:

1. Post retirement benefits - not beneficial to ratepayers.
2. Medical plan - accepted growth increase but not plan improvement.
3. Dental plan - accepted growth increase but not plan improvement.
4. Employee training - disallows employee growth.

Although the staff disallowed certain plan improvements, we are not certain that such disallowances are reasonable since no study was conducted to determine whether PG&E's benefits and/or total wage benefits were excessive when compared to other utilities. We will adopt PG&E's estimates modified to reflect the disallowance of employees we have made in our adopted results. We place PG&E on notice that in the future we will not authorize increases in post-retirement benefits.

g. Employee Training

The staff based its test year expenses for this expense category by using 1979 as a base and by increasing such base by the percentage of labor cost increases since that year. The staff expressed its concern with the 108% increase in this category between 1975-1979. While we do not agree with staff's estimate of no growth, we are of the opinion that expenditures in this category are somewhat discretionary and do not necessarily need to increase in proportion to the increase in the number of employees. We will not adopt PG&E's estimate but an estimate midway between staff's and PG&E's estimate as reasonable. This provides for some growth but recognizes certain economies of scale.

h. Employee Discounts

Another employee benefit which was addressed in this proceeding was the 25% discount on electric and gas bills for employees. The staff in response to a Commission request provided information on a comparison of electric and gas usage between PG&E employees and nonemployees. In order to obtain data that are socioeconomically comparable to the employees, PG&E obtained data by taking a 100% sample of employee accounts, and for nonemployees the next two residential accounts. The data show that for the 12 months ending January 1981, PG&E employees used 672 kWh of electricity compared to 620 kWh for nonemployees or an annual usage 8% higher than nonemployees. For gas, PG&E employees showed a 68 therm usage compared to 71 therms for nonemployees or about 4% less.

The staff report shows that should PG&E be required to eliminate employee discounts, a married employee would require a $1.47 increase for each dollar of discount lost and the cost to PG&E for each dollar of such compensation would be $1.18. By multiplying the $1.47 cost to the employee by the $1.18 cost; the total cost to PG&E would be approximately $1.75 for each dollar of discount eliminated for a married employee and a $2.16 cost for a single employee.

Although the staff did not take a position on eliminating employee discounts, the International Brotherhood of Electric Workers, Local No. 1245, strongly argued against elimination of this employee benefit. It considers the Commission's consideration of this issue as an intervention of the Commission into collective bargaining.

Employee discounts are an emotional issue in this day of progressively increasing utility rates. From a conservation viewpoint, it would appear to be a disincentive to conservation. The record in this proceeding, however, indicates that PG&E employees usage of utility services has been no more than the usage of nonemployees. From a rational economic viewpoint the elimination of employee discounts will result in higher costs since the unions have clearly indicated that such benefits would have to be replaced.

Rather than attempting to resolve this issue on a case-by-case basis we have opened an OII to obtain the comments and viewpoints of all utilities as well as other parties who may be affected by any action we may take on this issue.

i. Miscellaneous General Expenses

Bank Fees

The two chief areas of disagreement for this expense category were the staff's recommendation to eliminate bank fees paid by PG&E to support its lines of credit as an administrative and general expense and to include such costs in the calculation of the AFUDC rate. PG&E argues that bank fees are costs incurred by it as part of its cash management function. Since cash receipts and cash disbursements do not necessarily coincide, a line of credit is necessary to enable PG&E to meet its cash obligations. An established line of credit is a prerequisite for issuing commercial paper or borrowing money from banks on short notice. Whether PG&E actually borrows on a short-term basis or not, the lines of credit must be established and are normal costs incurred in the daily operations of PG&E. Witness Taylor further testified that PG&E has attempted to recover these costs through AFUDC calculations; however, PG&E has found that the application of fixed costs for lines of credit to the variable amounts of short-term debt includable in AFUDC calculations can cause distortions in the short-term debt rate. We concur with PG&E and find it reasonable to permit recovery of bank fees in a general rate proceeding.

Contribution to Gas Research Institute (GRI) and Electric Power Research Institute (EPRI)

Staff and PG&E have agreed that allowable expenses for EPRI and GRI should be based on actual billings for 1982. While we are encouraged by EPRI's commitment of funding to the Coolwater Coal Gasification Project, we are still concerned with the priorities evidenced by EPRI's overall RD&D program. We expect PG&E to use all of its influence to reform EPRI's budget so that it better reflects a resource mix appropriate to California. We will extensively review PG&E's contribution to EPRI in the next general rate case to determine whether these contributions are justified by the benefits they produce for California ratepayers. Our adopted expenses will be based on the actual billings to PG&E from EPRI for 1982 of $10,967,000 and for GRI of $872,000 based on the California-produced gas in this record. The staff further disallowed $100,000 of contributions for a project under auspices of Edison Electric Institute to establish a center for distribution of information relating to the Three Mile Island nuclear accident. PG&E did not challenge the adjustment, and we will adopt such adjustment. Similarly, the staff disallowed the entire $390,000 for costs related to the American Gas Association (AGA) communications program assertedly intended to promote conservation and efficient use of energy. PG&E eliminated 30% of this cost in making its estimate similar to a 30% disallowance of AGA dues by this Commission in prior decisions. AGA's communications program from our review of this record is nothing more than bland and general conservation advertising, therefore, we will adopt the staff's adjustment to exclude the entire contribution for the communications program. We have also eliminated all Edison Electric Institute and AGA dues for ratemaking purposes.

Depreciation

	Total Department		
	PG&E Revised	Staff Revised	Adopted
Electric Department	$331,641,000	$259,094,000	$261,108,000
Gas Department	$ 90,452,000	$ 90,452,000	$ 90,452,000

The only major issue on depreciation expense was related to PG&E's proposal for incremental depreciation on electric production plant of approximately $70 million. As discussed earlier in our rate of return and cash flow analysis section, we will not adopt such proposal. We will also make appropriate minor adjustments to PG&E's electric depreciation expense estimate for those issues relating to rate base raised by the staff and to which we may concur. The issue will be covered in our discussion of electric rate base.

The staff took no exception to PG&E's Gas Department's depreciation expense estimate for test year 1982.

Taxes

a. Property Taxes

The staff's estimate for property taxes were lower than PG&E's estimate. The staff based its estimate on some discussion with the staff of the State Board of Equalization which estimated a drop in ad valorem tax rates of five cents per $100 of assessed valuation within a year. PG&E argues that rather than a drop of five cents, the actual reduction in the tax rate for 1980-1981 from 1979-1980 was only one cent. PG&E based its property tax rate on the most current data. We will adopt PG&E's estimate for property taxes as more representative of what may occur in the test year.

b. Income Taxes

Since the initial filing of the respective Results of Operations exhibits of the staff and PG&E, the income tax laws applicable to public utilities have undergone substantial changes with the signing of the Tax Act on August 31, 1981. Among the significant changes are the adoption of ACRS which governs depreciation deductions, certain investment tax credit changes, the repeal of the repair allowance, and the normalization requirements of the Tax Act.

Since we have discussed the various issues relating to the ratemaking treatment of income taxes in our discussion of the Tax Act in Section III we will not duplicate such discussion in this section. Consistent with our previous discussion our adopted income tax expense and results of operations for both the Electric and Gas Departments for test year 1982 will be based on the full normalization requirements of the Tax Act.

Rate Base

	Total Department		(M$)
	PG&E Revised	Staff Revised	Adopted
Electric Department	$5,969,269	$5,507,548	$5,010,048
Gas Department	$1,652,510	$1,645,607	$1,613,369

The major difference in the Electric Department rate base estimates between staff and PG&E related to PG&E's NEAR proposal and incremental depreciation proposals. We are not adopting such proposals in this proceeding, thereby eliminating $475,000,000 for NEAR and $34,573,000 from the depreciation reserve by not adopting PG&E's incremental depreciation proposal or a net amount of $440,427,000 of the total difference of $461,721,000. Our adopted rate base will deduct the applicable deferred tax reserves resulting from the normalization of the tax benefits of ITC and ACRS depreciation as required by the Tax Act. The other areas of controversy between PG&E and the staff amounting to $21,294,000 are the following:

Diablo Info Center	$ 1,214,000
AFUDC Accruals	3,693,000
Load Management	7,079,000
A&G Clearing	2,879,000
Diablo Land Right-of-Way	6,468,000
Common PHFU	157,000
Working Cash	(18,821,000)
Deferred ITC	19,900,000
Depreciation Reserve	(1,275,000)
Total	$ 21,294,000

(Red Figure)

The staff recommended the disallowance of the investment in the Diablo Information Center since it was considered to be an institutional advertising and public relations-type expenditure. PG&E disagrees with the staff and states that the center also serves the function of an alternate control center. Both staff and PG&E indicate a willingness to resolve this issue in the Diablo rate base offset proceeding, A.58911. Final disposition of this center should be deferred to that proceeding and we will authorize PG&E to transfer the cost of the Diablo Information Center into a memorandum account and to accrue AFUDC. Thus, there is now no current impact on rates from the Diablo Information Center.

Staff further recommends that $6,468,000 recorded in PHFU representing investment in corridor land and land rights applicable to delivery of electricity to or from Diablo should not be included in rate base, but should be addressed in the Diablo offset proceeding together with other Diablo costs. PG&E's witness Taylor disagreed with the staff's recommendation since these plants had been allowed in rate base since August 1976, and also since these costs represent the remaining portion of the costs of transmission rights-of-way to the Diablo site that were left in PHFU when the initial transmission lines were placed in service. He contends that the transmission facilities have been a part of the grid for the last few years, providing alternate routing and improved system stability, therefore it was appropriate that the total rights-of-way costs should be in plant in service. We believe PG&E's position in this matter is reasonable and, therefore, we will not adopt the staff's recommendation.

a. Utah Coal Properties

The staff recommends that $13,929,440 of expenditures relating to coal reserves located in Utah be removed from PHFU and transferred to the Eureka Energy Company, a wholly owned subsidiary. These properties were acquired in May 1975 for use at the proposed Montezuma Power Plant and have been included in rate base. PG&E's witness did not disagree with the staff's recommendation, but testified that the recommendation was not complete in that PG&E should be required to return the carrying charges to the ratepayers and in the future should such properties be dedicated to utility use, it should be at the fair market value when such dedication takes place.

The staff in its brief argues that although these properties should be eliminated from rate base, at this time, its future treatment for ratemaking purposes should be determined in the course of PG&E's periodic Energy Exploration and Development Adjustment (EEDA) proceedings.

The Utah coal properties have been included in rate base since 1976, and it was obvious that the Commission considered the investments in coal reserves as prudent and properly includable in rate base. Since there is now some question on the future use of these properties, we will exclude this investment from rate base and require PG&E to record the investment in a memorandum account and accrue AFUDC and other necessary carrying costs pending ultimate resolution as to the status of these properties. Our treatment for this investment will enable PG&E to recover all carrying costs on these properties and at the same time preserve the ratepayer's right to any gains or losses on disposition of the properties. We will require PG&E to report to this Commission its proposed accounting and ratemaking treatment upon sale of the properties.

b. Nipomo Dunes

The staff further recommended that the gains resulting from the disposition of the Nipomo Dunes property of $171,456 be considered as an above-the-line gain. PG&E disagrees with the staff's contention since such property was never in rate base; therefore, the risk of holding such property was borne by the shareholders. We agree with PG&E and will not adopt the staff's recommendation.

c. Humboldt Nuclear Fuel

Staff recommended that nuclear fuel related to Humboldt should be treated in the same manner as other Humboldt plants. As expressed earlier in our discussion of Humboldt, we will authorize transfer of the Humboldt nuclear fuel to the memorandum CWIP account and permit PG&E to accrue AFUDC on such nuclear fuel until the ultimate disposition of Humboldt is decided.

d. Common Utility PHFU

The staff also proposed that Common Utility PHFU of $157,000 and $70,000 for the Electric and Gas Department, respectively, not be allowed in rate base because of the lack of a definite plan. PG&E's witness testified that there were plans for use of each of the properties in question although he had no specific dates when such properties would come in use. We believe that PG&E has justified the inclusion of such properties in rate base.

e. AFUDC Accrual Rate

The staff recommends a $21,521,000 reduction in AFUDC capitalization in 1979 and 1980 to conform with the AFUDC formula prescribed by Order 561 of the FERC. The staff contends that PG&E's computation was in error since it included only short-term borrowings in excess of balancing account undercollections and short-term investments. PG&E's witness testified that it was appropriate to offset short-term investments against short-term debt before calculating AFUDC. Since utilities often borrow more than they may need at any particular time, they invest any excess. The true cost of such short-term borrowing is obtained by taking the associated interest expense net of any offsetting income. We also do not disagree with PG&E's treatment of excluding short-term debt equivalent to the balancing accounts in 1980 and subsequent years since we have tied the interest rates on such balancing account to the commercial paper rate. This treatment is also approved by the FERC for 1980 and subsequent years. We will, therefore, only adopt the staff's adjustment for 1979 in relation to offsetting short-term debt against balancing accounts and for 1980 we will adopt the staff's adjustment in using a 13.95% return on equity instead of the 14.1% rate used by PG&E.

f. Fuel Oil Inventory

Our adopted Electric Department rate base will exclude fuel oil inventory since the carrying costs associated with such inventory are now recoverable under AER rates.

g. Canadian Gas Prepayments

TURN objects to the inclusion of $16.5 million in the Gas Department rate base resulting from the inclusion of PGT/PG&E take-or-pay obligations for Canadian gas. TURN's reasons for objecting are: (a) the amount of the take-or-pay liability, if any, to be incurred in 1981-1982 is highly uncertain, (b) the provisions of the amended PGT and Alberta and Southern (A&S) Contract would result in a reduction of the take-or-pay charges borne by the producers in the Alberta cost-of-service, and (c) the PGT and A&S contract is not an arm's-length agreement.

PG&E disagrees with TURN's contention and states that an understanding of the changes in the various contracts is necessary in understanding the reasonableness of the contracts and the transactions. PG&E states that A&S reached an agreement with the majority of its producers reducing its take-or-pay liability to one-fourth of the amount otherwise required by contract. The agreement did not reduce the amount of gas subject to take-or-pay or the volumetric level at which take-or-pay liability commenced. This amendment was conditioned on the requirement that the reduction in PGT's purchase obligation would be no more than 15%. A&S and PGT negotiated a 15% reduction in PGT's take-or-pay requirements which reduced PGT's daily contract quantity from 1,023 MMcf to 870 MMcf with a corresponding reduction in PG&E's daily contract quantity from 980 to 840 MMcf. The net effect is that PG&E's take-or-pay liability is triggered at 76.5% of 980 MMcf instead of at the previous 90% point.

PG&E argues that TURN's emphasis on PG&E's obligation to pay for its take-or-pay volumes at the contract level compared to A&S paying for its take-or-pay volumes at one-fourth of the amount otherwise provided represents a myopic comparison. TURN ignores the fact that PG&E and PGT received a substantial reduction in the volume triggering their take-or-pay liability while A&S received no such reduction in its take-or-pay volumes. PG&E further argues that TURN's contention that the PGT and A&S contracts are less than arm's length and therefore not negotiated on a reasonable business basis, is unwarranted. PG&E further states that TURN fails to understand that the producers in renegotiating its contract with A&S wanted to restrict the reduction in PGT's purchase obligation to no more than 15%. Requiring PGT to make the full unit take-or-pay payment for its take-or-pay volumes was one way of encouraging PGT to keep its purchase volumes up. A reduction of the take-or-pay payment to one-quarter of the otherwise applicable amount would have been contrary to the producers' interests.

PG&E also disagrees with TURN's criticism of its estimate as being unreasonable. PG&E's estimate was based on average test year conditions and therefore does not assume abnormal conditions that TURN conjectures could take place.

We believe carrying costs involved in any Canadian take-or-pay payments should properly be considered in a GAC proceeding because of the variable nature of take-or-pay payments; therefore, we will exclude Canadian take-or-pay payments from Gas Department rate base.

VII. Results of Operations - Gas Department

Table VII-1 presents a comparison of PG&E's and staff's results of operations for the Gas Department for test year 1982. Our discussion under the Electric Department Results of Operations on inflation factors, recurring expenses, and deferred work apply equally to the Gas Department. The discussion in this section will be restricted to disputed items peculiar to the Gas Department and not covered previously in the Electric Department Results of Operations. Similar to our discussion for the Electric Department, Table VII-1 and our related discussion of the difference between PG&E and staff estimates do not reflect the change in the labor escalation factor shown in Exhibit 180a. Our adopted results of operations as shown in Table VII-2 reflects the more current labor escalation factor as well as the effects of the Tax Act on results of operations. Table VII-3 sets forth the adopted gas margin for test year 1982.

Table VII-1

PACIFIC GAS AND ELECTRIC COMPANY

GAS DEPARTMENT
RESULTS OF OPERATIONS
YEAR 1982

(000's Omitted)

	PGandE Revised (A)	Staff Revised (B)	PGandE Exceeds Staff (C)
Gross Operating Revenues	$ 3.562.552	$ 3.562.552	$ 0
Operating Expenses:			
Natural Gas Purchased	3.007.656	3.007.306	(350)
Natural Gas Used by Gas Dept.	(22.746)	(22.746)	0
Other Production	1.274	1.267	7
Storage	5.082	4.527	555
Transmission	43.562	41.435	2.127
Distribution	93.431	92.369	1.062
Customer's Accounts	59.726	54.437	5.289
Uncollectibles	3.540	3.540	0
Customer Service and Informational	25.625	21.709	3.917
Load Management	1.236	646	590
Administrative and General	95.778	79.693	16.085
Franchise Requirements	23.539	23.539	0
Subtotal	3.237.704	3.307.722	29.982
Escalation Adj. - Labor	584	554	30
- Non labor	(618)	672	(1.290)
Total Expenses Excluding Taxes and Depreciation	3.237.670	3.308.948	28.722
Taxes:			
Property	13.558	13.436	122
Payroll and Business	12.942	12.864	78
State Corporation Franchise	3.389 (A)	6.243 (A)	(2.854)
Federal Income	4.853	6.844	(1.991)
Total Taxes	34.742	39.387	(4.645)
Depreciation	90.452	90.452	0
Total Operating Expenses	3.462.864	3.438.787	24.077
Net for Return	99.688	123.765	(24.077)
Rate Base	$ 1.652.510	$ 1.645.607	$ 6.903
Rate of Return - Rate Base	6.03%	7.52%	(1.49%)
- Equity	1.51%	5.02%	(3.51%)
Revenue Requirements Proposed	3.780.774	3.701.886	78.888
Additional Revenue Requirement	$ 218.222	$ 139.334	$ 78.888
Net to Gross Multiplier	2.070655	2.070655	

(A) Includes full investment tax credits.

Table VII-2

PACIFIC GAS AND ELECTRIC COMPANY

Gas Department
Adopted Summary of Earnings
Test Year 1982 at Present and Authorized Rates
(000's Omitted)

	Present Rates	Authorized Rates
Operating Revenues	$3,562,552	$3,765,093
Operating Expenses		
Production	1,267	1,267
Cost of Gas less Dept. Use	2,984,910	2,984,910
Storage	4,958	4,958
Transmission	42,861	42,861
Distribution	92,369	92,369
Customer Account	62,275	62,579
Customer Service & Info.	16,868	16,868
Load Management	1,033	1,033
Admin. & General	106,833	108,695
Subtotal	3,313,374	3,315,540
Wage Adjustment	1,691	1,691
Escalation	641	641
Subtotal after Adjustment	3,315,706	3,317,872
Book Depreciation	90,452	90,452
Taxes Other Than Income	26,038	26,038
State Corp. Franchise Tax	6,284	25,520
Federal Income Tax	25,056	108,380
Total Operating Expenses	3,463,536	3,568,262
Net Operating Revenue	99,016	196,831
Rate Base	1,613,369	1,613,369
Rate of Return	6.14%	12.20%

Table VII-3

PACIFIC GAS AND ELECTRIC COMPANY

Gas Margin
Test Year 1982

	Amount (M$)	
Revenue at Present Rates 1/		$3,562,552
Revenue Increase		202,541
Total Revenue		3,765,093
Gas Purchases	$2,968,605	
Franchise Requirements and Uncollectibles	22,737	
Cost of Gas Sold		(2,991,342)
Gross Margin		773,751
Miscellaneous Revenue		(1,452)
Sales Margin		$ 772,299

1/ Excludes: GEDA Rev. of $30,145
CFA Rev. of $8,759
SFA Rev. of $3,061.

Production Expenses

	PG&E Revised	Staff Revised	Adopted
Production Expenses	$1,274,000	$1,267,000	$1,267,000

The difference in the two estimates is due to the difference in escalation rates (inflation factor) for nonlabor expenses. We will adopt the staff's estimate since we have adopted the staff's nonlabor escalation factor.

Storage Expenses

	PG&E Revised	Staff Revised	Adopted
Storage Expenses	$5,082,000	$4,527,000	$4,958,000

$31,000 of the difference in storage operation expenses and $42,000 of the difference in storage maintenance expenses is due to the previously discussed difference in nonlabor inflation factor. The remainder of the difference is due to the staff's disallowance of 8.4 additional employees for storage operations and expenses associated with the maintenance of the Ten Section Field. PG&E's witness testified that the 15.4 positions were necessary to add an additional person to each shift at the MacDonald Island Field. Although PG&E currently has only one person on each shift, it has found the arrangement unsatisfactory because of the size of the field and with only one person on duty the control center has to be abandoned if the operator must go out into the field to operate equipment. The staff is allowing seven employees for the Los Medanos Gas Storage Facility and believes that by implementing the findings and conclusions of the Cresap, McCormick and Paget (CMP) report, PG&E by increased productivity will be able to operate the gas storage operations with the additional seven employees rather than the 15.4 requested. While the staff witness relies upon the CMP report for productivity increases he was unable to offer any specific recommendations on how PG&E could achieve this increase in productivity.

We will adopt PG&E's manpower requirement for our test year 1982 estimate. To the extent PG&E can achieve increased productivity by following the recommendations contained in the CMP report, these efficiencies can be considered in arriving at estimates in future general rate proceedings.

We will adopt the staff's recommendation to not allow maintenance expenses for the Ten Section Field since such field is not being included in rate base in the test year. Such costs may be properly capitalized and recovered if found appropriate in the future.

Transmission Expenses

	PG&E Revised	Staff Revised	Adopted
Transmission Expenses	$43,562,000	$41,453,000	$42,861,000

Of the $2,127,000 difference between the staff's and PG&E's expenses, the staff's use of a lower nonlabor escalation rate accounted for lower operation expenses and maintenance expenses estimates of $152,000 and $146,000, respectively. The chief area of difference between the two estimates was due to the disallowance by the staff of some 27.1 additional personnel requested by PG&E for test year 1982. PG&E argues that the additional positions are necessary since PG&E had anticipated a change in its source of natural gas, thereby enabling it to reduce its take of expensive Canadian gas and increase its take of cheaper gas from El Paso. PG&E had been anticipating a gradual decline in the availability of El Paso gas and, therefore, had reduced the maintenance and manpower associated with the pipeline bringing El Paso gas into PG&E's service territory to a level appropriate for such lower volumes. Since the El Paso supply situation has changed in the past year, it is now anticipated that a substantial increase in the supply of gas from El Paso would be available in test year 1982. In order to make this cheaper gas available to its ratepayers, PG&E states that the manpower available to operate this pipeline must be increased. Considering the age of Main 300, which brings El Paso gas to PG&E's service area, we consider the additional cost of adding personnel to operate and maintain Main 300 will be returned manyfold to ratepayers by the lower price paid for El Paso gas. We will therefore reject the staff's adjustment for the additional pipeline operational employees.

For transmission mains maintenance expenses we believe the staff methodology in using a five-year average is superior to PG&E's use of 1979 data. We will, therefore, adopt the staff's estimate of transmission mains maintenance expenses. Although we agree with the staff's use of a five-year average in estimating maintenance of compressor station equipment, we agree that PG&E's contention that fine tuning of compressor station equipment is essential because of the increasing cost of natural gas is also valid. We will, therefore, adopt as reasonable an estimate midway between the staff and PG&E's estimate.

Distribution Expenses

	PG&E Revised	Staff Revised	Adopted
Distribution Expenses	$93,431,000	$92,369,000	$92,369,000

The difference in the two estimates is due to the difference in escalation rates for nonlabor expenses. We will adopt the staff's estimate as reasonable since we have adopted the staff's nonlabor escalation factor.

VIII. Conservation, Load Management

A. Conservation Programs

In D.91107 we reiterated the critical need for improved energy efficiency and our expectations of PG&E in the area of conservation:

> "Conservation is a valuable energy resource which PG&E and California's other energy utilities must aggressively develop. The decision commits PG&E to increased development and full cost-effective implementation of conservation opportunities. We expect the utility to invest a dollar in conservation whenever that dollar offers ratepayers the potential for conserved energy which is equal to or less costly than alternative energy sources.
>
> "For the 1980 test year PG&E has been authorized a total expenditure of $65,601,000 for load management and energy conservation programs. In doing so, PG&E has been advised that it must demonstrate a more aggressive and innovative attitude toward accelerating its overall cost-effective conservation efforts. Dramatic results in the 1980 test year are expected by the Commission pursuant to PG&E's vigorous implementation of several energy conservation efforts, such as solar, insulation, load management (both residential and commercial-industrial) cogeneration, and conservation voltage regulation."

In view of the size of PG&E's total proposed conservation budget for test year 1982, the various parties devoted considerable time and effort on cross examining the various witnesses who testified in the area of conservation.

PG&E has requested a budget of $201.5 million for conservation programs. This request includes:

Mandated Programs	
Weatherization ZIP	$33 million
Residential Conservation Service	$17.5 million
Demonstration Solar Financing Program	$19 million
Load Management	$60 million
Other Programs (Operating Expenses)	$72 million

A significant portion of the above conservation expenditures consists of capital expenditures. The operating expense portion is contained in customer service expenses. Expenditures for the ZIP, RCS, and demonstration solar financing programs are being considered in other proceedings. Today, under separate order, we will approve $29.0 million for ZIP and $12.0 million for RCS.

PG&E estimates life cycle savings for 1982 customer-related programs to be 4.1 billion kwh and 957 million therms.

PG&E's conservation exhibits also include $69 million for various programs more appropriately characterized as system efficiency, research, and energy production activities. These programs are considered elsewhere in this decision.

PG&E's witness R. M. Mertz testified on PG&E's conservation programs and of its willingness to vigorously pursue conservation and pioneer various conservation and load management programs. Mertz further testified on the importance of obtaining adequate funding if PG&E is to be able to continue and take an innovative approach to conservation. E. A. Heim testified on PG&E's conservation program measurement techniques, conservation program goals, and the results of the cost-effectiveness evaluations of PG&E's customer-related conservation programs. He also discussed PG&E's efforts to comply with Energy Commission's load management standards. Load management testimony was presented by R. P. Thompson.

The staff witnesses on conservation were M. Jhala and C. Danforth of the Energy Conservation Branch (ECB). Jhala testified on the various conservation programs of PG&E for test year 1982 and Danforth was the witness on quantitative measurement of PG&E's conservation program. The staff witnesses on load management were A. Fa'arman and J. McIlvain.

The Energy Commission witnesses were P. Khalsa and D. Johnson on conservation quantification, M. Clark, W. Bakken, D. MacCurdy, Jr., W. Marcus, and P. Conroy on conservation incentives program, and S. Dhar on load management programs.

PG&E in its conservation exhibit sets forth various conservation programs for 1982 which were analyzed by the staff in arriving at its recommended allowance for the respective programs. In our discussion of PG&E's proposed conservation program we will initially compare the staff and PG&E estimates and thereafter the Energy Commission proposals.

Table VIII-1 sets forth PG&E's and staff's estimates for conservation programs for the Electric and Gas Departments for test year 1982 by programs excluding load management. The various customer-related conservation programs are discussed in subsection A, load management programs in subsection B, and cost-effectiveness analysis in subsection C.

Table VIII-1

PACIFIC GAS AND ELECTRIC COMPANY
CUSTOMER SERVICE & INFORMATIONAL EXPENSE
By Program
(Excluding Load Management)

Electric Department
Test Year 1982
(000's Omitted)

PROGRAM	PGandE ORIGINAL AS FILED (A)	PGandE REVISED (B)	STAFF REVISED (C)	PGandE EXCEEDS STAFF (D)
Conservation				
Residential Conservation Svc Including Solar	$ 9,165	(A) $ 2,738	$ 2,238	$ 500
Homes, Appliances & Systems	5,418	5,418	5,160	258
Community and Consumer Svc	3,686	3,686	3,093	593
Commercial-Industrial-Agric	30,433	30,433	24,729	5,704
Program Evaluation	550	550	950	(400)
Total Conservation	$49,252	$42,825	$36,170	$ 6,655
Marketing Service	$ 3,506	$ 3,506	$ 3,366	$ 140
TOTAL	$52,758	$46,331	$39,536	$ 6,795

(A) Staff reduction of $6,427,000 in the Residential Conservation Service (RCS) program. PGandE and Staff agree that cost recovery will be the subject of the separate proceeding discussed in the Commission Decision No. 92653 (Application No. 59537 - ZIP). Chapter 3, Page 3-1, Section A, Paragraphs 1 and 2.

Gas Department
Test Year 1982
(000's Omitted)

PROGRAM	PGandE ORIGINAL AS FILED (A)	PGandE REVISED (B)	STAFF REVISED (C)	PGandE EXCEEDS STAFF (D)
Conservation				
Residential Conservation Svc Including Solar	$25,435	(A) $ 2,113	$ 1,613	$ 500
Homes, Appliances & Systems	4,069	4,069	3,828	241
Community and Consumer Svc	3,114	3,114	2,526	588
Commercial-Industrial-Agric	14,567	14,567	11,630	2,937
Program Evaluation	550	550	950	(400)
Total Conservation	$47,735	$24,413	$20,547	$ 3,866
Marketing Service	$ 1,213	$ 1,213	$ 1,162	$ 51
TOTAL	$48,948	$25,626	$21,709	$ 3,917

(A) Staff reduction of $23,322,000 in the Residential Conservation Service (RCS) program. PGandE and Staff agree that cost recovery will be the subject of the separate proceeding discussed in the Commission Decision No. 92653 (Application No. 59537 - ZIP). Chapter 3, Pg. 3-1, Section A, Para. 1 and 2.

In this proceeding, PG&E has requested nearly $72 million for conservation expenses other than load management. Staff has recommended reductions in several programs and would allow nearly $62 million. One-half of the disallowance proposed by staff can be found in a single program - Load Management Standards (LMS) incentives for commercial and industrial customers.

PG&E successfully demonstrated the value and cost-effectiveness of many of its programs. Our staff has shown several areas in which the budget could be reduced. Energy Commission's witnesses demonstrated the great cost-effectiveness of LMS programs while also offering proposals for several incentive programs.

In D.84902, we first announced we would evaluate the "vigor, imagination, and effectiveness" of the conservation efforts of PG&E when determining PG&E's rate of return. In this proceeding, it has been made clear that no penalty is in order.

However, while PG&E has developed a comprehensive and growing conservation effort, question still remains as to the effectiveness of PG&E's conservation programs.

Two fundamental issues are inherent in a review of program effectiveness: implementation and evaluation. The bulk of the testimony of conservation witnesses revolved around these two issues.

The often acrimonious debate on implementation can be viewed as a search for the best mousetrap. PG&E presented its program proposals and budgets, while the staff and Energy Commission offered what they believed to be better programs or better budgets. Some improvements became apparent as a result of this triangulation.

We have in the last six years reviewed and approved utility conservation programs in much more detail than other utility activities. We recognized that this was a new area of endeavor for the utilities, pursued in large part at the Commission's direction, and therefore initially requiring more oversight by us.

We now believe that to create the proper environment for management to maximize the cost-effectiveness and efficiency of conservation programs in the future, we should depart from our past practice of establishing binding budget levels for each specific program. We shall in this decision comment on many of the specific programs proposed by PG&E for the test year. We shall also discuss those program areas like general conservation advertising and information which should not receive any ratepayer support.

Beyond that, however, we shall establish certain general conservation policy guidelines and adopt an overall conservation budget for PG&E. Within the boundaries of these guidelines and budget, PG&E's management will have discretion to establish priorities and allocate resources to maximize energy savings.

We shall give management discretion to reallocate funds among individual programs in amounts up to $2,500,000 provided that no funds are reallocated among the four major categories of Residential, C-I-A, Conservation Evaluation, and Load Management. Budget adjustments in excess of $2,500,000 shall be made the subject of an advice letter filing.

Funds allocated under this budget shall only be spent on conservation and load management programs. Any funds not spent during a year shall be carried forward for future use in conservation and load management activities. We shall expect PG&E to explain in a future rate proceeding its inability to use any of these funds.

Policies

We adopt several general policies to guide conservation spending during 1982 and 1983. These relate to equity among customer classifications, advertising budgets, load management, and use of in-place capability.

We expect PG&E to target roughly comparable percentage savings in each of several classes of customers. These classes include residential, small commercial, large commercial, industrial, agricultural, and the schools, hospitals, and public buildings category. Because it appears that greater savings can be achieved per dollar of overhead with larger customers, this will likely require greater expenditures and effort to reach smaller customers. We believe this expenditure is justified to assure that all PG&E customers have access to the benefits of PG&E's conservation programs.

There is great controversy over the size and effectiveness of PG&E conservation advertising and promotion programs. We believe significant budget reductions are needed in this area and can be effected without significant loss to the overall conservation effort. There are preferable alternatives to many advertising and promotion programs. We are particularly impressed by the potential for increased use of effective bill stuffers, the use of PG&E's broad community infrastructure, and the use of outside firms and agencies to carry the message of PG&E's programs. We shall reduce the advertising component of PG&E's proposed total conservation budget by $5,000,000. This reduction is reflected in the amounts included in rates for specific conservation programs, but management may allocate the reduction among programs as it deems best. Advertising should be program specific and should be designed to produce measurable results.

Likewise, we are eliminating or reducing several programs that are primarily educational or promotional in nature. It has been eight years since the Arab oil embargo and there have been several years of rapid increases in utility rates. The need for conservation is clear to most ratepayers. The time for general education and promotion has passed. PG&E must now focus on the specific programs it offers customers who decide to take action.

We are thus eliminating all programs in the Consumer Services category, the Community Partnership Program, the Golden Gate Energy Center, the Demonstration Retrofit Program, and the C-I-A Awards Program. We are reducing the budget in the Community Cooperative Conservation Program.

PG&E has proposed vigorous load management programs. Despite extensive cuts recommended by our staff, we are persuaded that these programs are likely to prove cost-effective and have great potential. These programs may become particularly significant if uncertainties continue regarding the start-up of Diablo.

While we authorize PG&E to proceed with the load management programs presented in its exhibits, we believe certain budget adjustments are in order. Given the broad coverage of the programs to be implemented, we see no need to extablish the $1.5 million reserve fund requested by PG&E. Nor do we feel it appropriate to include the ongoing load research programs of PG&E as a load management item. Load research expenses should be included in categories relating to rates and tariffs, supply planning, and RD&D. We shall remove this $6.045 million item from the load management budget but will allow $5.6 million in rates giving PG&E discretion to place these expenditures in more appropriate budget categories. For the purpose of this proceeding, load research is treated as an A&G item.

Our concerns with the remainder of the load management budget are twofold. As we have done with many of PG&E's requests, we find some belt tightening in order although we find the programs meritorious. Load management is a rapidly expanding program which will require close management scrutiny to control costs. We shall cut the remaining load management request of $52,404,000 by approximately 10% and allow management to allocate the reduction to achieve the stated market penetration goals in the most efficient manner.

Our second concern related to five experimental load management projects about which our staff raised questions of feasibility and cost-effectiveness. These programs are:

Residential Time-of-Use rates,
Residential programmable controllers,
Residential Smart Duty Controllers,
Commercial Air Conditioning Load Deferral, and
Commercial Programmable Controllers.

We recognize that these programs are intended to determine feasibility and cost-effectiveness and thus do not adopt the specific reductions proposed by staff. Nevertheless, management should consider whether some of these programs could be expanded at a slower pace while still meeting evaluation objectives. It may be necessary to reduce expenditures for experimental programs to achieve market penetration goals for other load management programs within the authorized budget.

Finally, we believe PG&E should emphasize use of its available talent, as well as outside talent, to implement conservation programs. Experience indicates that start-up costs and problems tend to be severe in the highly labor intensive conservation programs. Contracting with outside groups in both the public and private sector may offer the most practical alternative to these problems in many cases. Programs such as the Cooperative Electricity Management Program have produced outstanding results very quickly and at low cost. There are many very capable energy efficiency analysts in the private sector who could help PG&E accelerate programs in the mid- and large-user markets. Finally, redeployment of persons within PG&E may be preferable to hiring large numbers of new people.

Adopted Budget

PG&E has requested $132,147,000 for conservation and load management programs in test year 1982 not including ZIP or RCS. Staff has recommended a budget of $105,683,000, a reduction of $26,464,000 or 20%. In addition, staff recommends that nearly $13 million of its proposed budget be kept in a contingency fund subject to further approvals by staff or the Commission during the test year. Staff's proposed budget reductions can be found on a program-by-program basis in the staff exhibits.

We have previously indicated that we will not adopt the staff recommended approach of establishing the conservation budget on a program-by-program basis. On the other hand, we have decided to reduce conservation advertising and promotional expenses even more than the staff has proposed and have eliminated several programs. Thus, of the $132,147,000 proposed budget, we have reduced advertising by $5,000,000, transferred load research expense (estimated by PG&E at $6,045,000) to A&G expenses, and have fixed $47,574,000 as the load management budget.

This leaves $66,957,000 of PG&E's request. At the outset, we note that $4,719,000 of this amount is expense for marketing services. This item does not appear in PG&E's conservation exhibit and bears no relation to the conservation programs. While we shall allow the staff recommended level of $4,528,000 for this item in rates, we expect management in future to place this item in a different budget category.

The remaining $62,238,000 we shall reduce by approximately 31% or $19,289,000. We believe that a budget reduction of this size, coupled with a grant of authority to management to allocate the reduction within the guidelines noted earlier, will "trim the fat" in PG&E's conservation program without hampering its effectiveness. In order to determine this overall budget figure we reviewed the level and productivity of PG&E's individual proposed programs. The budget reductions we have developed represent our concern about the productivity of certain programs, which is set out in detail below. However, we recognize the benefit of direct management experience in the implementation of such programs as well as the importance of developing internally consistent and complete conservation programs. Thus, our assessment will not be strictly binding. If management feels that some reallocation of expenditures is appropriate to meet conservation objectives and maximize the cost-effectiveness of the overall conservation program, we authorize them the discretion to make such a reallocation within the constraints discussed earlier. We do reiterate here, however, our objection to increased expenditures for general advertising and information programs.

We note that, despite the extent of our cuts in the scale of PG&E's proposed conservation expenditures, the total conservation budget we are authorizing for 1982 will be $42,949,000. This represents an increase of nearly $10 million over the company's conservation expenditures in 1981 for comparable programs. We are also authorizing significant increases in expenditures for the ZIP and RCS programs. These actions will permit a steady expansion of the most cost-effective conservation efforts while maintaining spending constraints consistent with those felt by all business enterprises in this time of economic hardship.

In order to maintain the momentum of PG&E's conservation efforts in a context of determined but gradual program expansion, we see value in the Energy Commission's suggestion that the attrition allowance should take account of the high priority of conservation programs by adjusting rates for 1983 to cover the entire increase in projected conservation expenses for that year. We do not adopt that proposal, because it might encourage wasteful program expansion. We will authorize, as an alternative, a $10 million upward adjustment in the 1983 revenue requirement to reflect conservation program growth in addition to but simultaneous with the attrition rate adjustment provided for by the adopted ARA mechanism. We caution that our admonition to curtail advertising and promotional expense applies as well to the use of these additional funds in 1983.

Program Discussion

RCS Programs

Although PG&E initially included amounts in its estimate for RCS Programs mandated by the federal government and directed by the Energy Commission, it has subsequently revised its estimate to exclude costs related to RCS Home Audits and Renewable Resources since they will be the subject of a separate proceeding. The remaining RCS program costs to be recovered in this proceeding are:

	PG&E Revised	Staff Revised	Included in Rates
Solar Technology	$2,480,000	$1,480,000	$ -
Swimming Pool Pump Load Management Programs	388,000	388,000	a/
General Customer Inquiries	1,983,000	1,983,000	1,800,000
	$4,851,000	$3,851,000	$1,800,000

a/ Transferred to load management.

The staff disagrees with PG&E's estimated cost for a Solar Technology Assessment and Referral (STAR) audit of $3,100 per audit on the average. PG&E generally requires a commercial Conservation Energy Utilization Audit (EUA) or one of PG&E's other nonresidential conservation audits as a prerequisite to a STAR audit. Combining the cost of an EUA estimated to be $2,760 per customer with a STAR audit would require a $5,860 audit cost for a potential solar customer. Staff witness Jhala believes that the cost of a STAR audit should not exceed the cost of an EUA and that the STAR program can be reduced by $1 million by eliminating some of the marketing, customer contact activities, and by reducing consultant services. ECB states that most of the customers will be reached under the EUA and the estimated savings will be achieved.

We are impressed by staff's argument but would draw another conclusion from it. If these customers will be reached by an EUA, then we believe that this one audit should be sufficient. It should provide limited information on solar applications and urge those customers who have the potential to use solar energy cost-effectively to pursue this option with a qualified architect or contractor. We will therefore not grant the $2.48 million requested for this program.

The swimming pool pump load management program was ordered by Energy Commission and is a very cost-effective program. We will authorize PG&E to continue it at the requested level of $388,000 per year but believe it should be included as a load management program within the overall budget authorized for such programs.

We are budgeting the expense for general customer inquiries at a level equivalent to that for the year 1981.

Home, Appliances, and Systems

Home	PG&E Revised	Staff Revised	Included in Rates
Voluntary Builder Program	$3,226,000	$2,926,000	$1,900,000
Demonstration/Retrofit Energy Conservation Home	199,000	-	-
Master Meter Conversion	387,000	387,000	387,000
Appliance			
Sales Person Incentives	783,000	900,000	
Appliance Efficiency Marketing	4,256,000	4,139,000	3,874,000
Second Refrigerator	636,000	636,000	
Total	$9,487,000	$8,988,000	$6,161,000

The Voluntary Builder Program has been a successful program but its continuance must be seen in the context of the Energy Commission's more stringent revised Residential Building Standards, sharply reduced building activity, and our imminent decision in the

Line Extension Case (C.10260). We believe that these factors will limit the future opportunities for this program and will therefore only grant funds for its continuance at last year's budget level. Should PG&E demonstrate greater results than we anticipate, we will certainly look favorably upon this in the next general rate case.

Staff agrees with PG&E's budgeted total of $387,000 for the master meter conversion program. By conversion of master-metered dwelling units to single meter units, PG&E estimates that a 20% energy savings will result. We will authorize continuation of this program at the requested level.

Appliance Programs

PG&E has requested $5.675 million for three conservation programs in the appliance area-sales person incentives, appliance efficiency marketing, and elimination of second refrigerators. The staff was generally supportive of appliance efficiency programs. We believe these programs have merit but question the large promotional components of the programs. We will grant funds approximately equal to two-thirds of the proposed expenditures to be used as PG&E finds most cost-effective in the entire appliance area. As with other authorized conservation programs, PG&E may take funds from a nonappliance program and transfer them to this area should it find it more cost-effective to do so.

Community and Consumer Services Programs

A comparison of PG&E's and staff's estimates for Community and Consumer Services Conservation Programs is shown below:

	PG&E Estimate	Staff Estimate	Included in Rates
Community Services			
Community Cooperative	$ 232,000	$ 172,000	$ 172,000
Community Partnership	358,000	-	-
Division Conservation Representative	1,662,000	1,662,000	1,662,000
Stockton Training Center	1,387,000	1,030,000	1,087,000
Golden Gate Energy Center	27,000	27,000	-
Consumer Services			
Consumer Education	888,000	849,000	-
Consumer Exhibits	376,000	376,000	-
Elementary Mobile School Van	367,000	-	-
General Conservation Advertising	1,503,000	1,503,000	-
Total	$6,800,000	$5,619,000	$2,921,000

As previously indicated, we shall disallow all funds for programs in the Consumer Services category as well as for the Community Partnership Program and the Golden Gate Energy Center.

Under the Community Cooperative Conservation Program, PG&E works with various organizations to implement conservation programs and activities such as energy fairs, forums, seminars, general exhibits, and contracts. The ECB recommends the deletion of $60,000 from the proposed budget of $232,000 intended for purchases of incentive prizes such as hot cups, frisbees, key chains, etc. ECB's witness Jhala believes the incentives are unnecessary. We concur in this reduction.

The Division Community Conservation Representatives Program was created to promote energy conservation programs to assist low income, disabled, and senior citizen groups, and neighborhood organizations. PG&E has budgeted $1,662,000 for this program in 1982, including $525,000 for contracting 15 Economic Development Centers. Since this program was just initiated in 1981, the staff recommends continuation of this program in 1982 only if the 1981 program is successful. We concur in staff's recommendation.

The Stockton Training Center provides workshops and classes for basic weatherization, RCS, and solar. The training facilities are designed to comply with the RCS section of the National Energy Conservation Policy Act. PG&E requests $1,387,000 to operate this center in 1982. The center is one of the leading success stories in PG&E's conservation effort, and we agree that it should be continued.

Within the reduced budget for Community Services authorized here, we shall leave to management the decision on how to expend funds on the authorized programs in this category. Management also has the discretion to move funds from the Community Services category to other conservation programs to enhance overall effectiveness of the conservation effort.

Commercial-Industrial-
Agricultural (C-I-A)
Conservation Services

The following is a comparison of C-I-A Conservation Services Program for test year 1982 as estimated by PG&E and the staff:

C-I-A Conservation Services Programs

	PG&E	ECB	Included in Rates
	(000 Omitted)		
Audit Programs			
C-I-A Energy Utilization Audits	$ 8,829	$ 7,360	$ 7,360
Computerized Audit	5,041	4,241	4,241
Agricultural Irrigation Service	1,883	1,883	1,883
Commercial New Building Review	2,366	1,818	-
Load Management Standards Incentives	13,187	8,500	8,500
Energy Management Development			
Energy Management Development Program	1,120	1,120	
College and University	1,993	1,993	5,672
School Plant	2,664	2,664	
Hospital	2,276	2,276	
Technical Support			
Demonstration/Retrofit Projects	536	536	536
Lighting Analysis	266	266	266
Application Engineering	803	803	803
C-I-A Energy Conservation Information Center	751	751	376
In-House Energy Conservation Program	124	124	62
C-I-A Communication Support	1,292	727	646
C-I-A Awards	624	365	-
C-I-A Seminars	1,245	932	622
Total	$45,000	$36,359	$30,967

The C-I-A sector accounts for over 60% of PG&E's electric sales and over 40% of its natural gas sales. PG&E's 1982 budget of $45 million for C-I-A programs is 46% of the total for all customer-related conservation programs. PG&E estimates that its 1982 C-I-A programs will generate life cycle energy savings of 2.8 billion kWh and peak demand reductions of 58.2 MW of electricity plus life cycle savings of 407 million therms of gas.

C-I-A Energy
<u>Utilization Audits</u>

By 1985 PG&E proposes to contact all C-I-A customers either by formal audits or workbooks. PG&E will contact for formal audit 35,000 large customers using over 100,000 kWh of electricity and/or 50,000 therms of gas per year. The EUA auditor will prepare a written report recommending specific conservation techniques or equipment. In 1982 PG&E will conduct 3,200 EUAs using 129 auditors at an average cost of $2,760 per audit. The ECB staff believes PG&E's labor and marketing costs are overstated and believes that such audits can be conducted at an average cost of $2,300 per audit. PG&E contends that its budgeted manpower is essential since, as the program expands, the number of call-backs at 6-, 18-, and 42-month intervals also increases, therefore, justifying the need for increased manpower.

We endorse this program and the use of call backs to determine conservation measures undertaken and to reinforce audit recommendations. On the other hand, we believe audit efficiencies will improve as PG&E moves down the learning curve and that the availability of incentives should reduce call-back costs somewhat. We will therefore use staff's estimated expenditures figure and urge PG&E to manage this program carefully to reduce costs.

Computerized Audit
<u>Program</u>

This program will provide small nonresidential customers with a computerized EUA. The program is an integral part of PG&E's LMS program for commercial customers. For 1982 PG&E plans to make 18,000 audits costing $5,041,000; however, the staff believes this goal is unachievable since a marketing research study suggests only a 2.4% response rate. The staff reduced the goal to 14,000 audits by making an $800,000 reduction in the labor portion of this program.

While we do not reject PG&E's goal, we believe the staff figures may be more realistic for this rate case. If PG&E's estimate of customer response is correct, it will demonstrate the effectiveness of this program and the desirability of further expansion.

Agricultural Irrigation
Service

Under this program PG&E will test 15,000 pumps owned by farmers or water companies in 1982 at an estimated cost of $1,883,000. Owners of inefficient pumps are provided reports and encouraged to make improvements. The staff believes the cost of this program is reasonable. We concur.

Commercial New
Building Review

PG&E has budgeted $2,366,000 in 1982 for this program designed to encourage building owners, designers, architects, and contractors to incorporate energy conservation measures exceeding building standards. The ECB has recommended reducing the incentive package from $1,548 for each building to $1,000 for an adjusted program cost of $1,817,536.

While this program may produce desirable results, this is one area for which we believe significant budget cuts are in order. Owners, designers, and architects of commercial buildings should now be fully aware of the need for energy efficient design to assure profitable operation. Trained professionals have the necessary capability to design and build efficient buildings. We grant no funds for this program. However, consistent with our policy favoring management discretion, we leave PG&E free to fund this program out of its overall C-I-A budget if in its judgment such a program deserves priority.

LMS Incentives

Under the LMS Incentives Program, PG&E plans to offer on-site EUAs to its 800 largest customers and, may, where appropriate, employ financial incentives to stimulate greater conservation investments by these customers. In 1982 PG&E will offer various forms of financial incentives to promote the use of selected energy conservation measures. The ECB staff agrees that it may be necessary to stimulate commercial customers to invest in energy saving measures, but it believes PG&E's program is too vague. It recommends a budget of $8,500,000 to be placed in a contingency fund to be used on incentive plans with Commission approval. Energy Commission strongly supported PG&E's proposal.

We believe this program has substantial merit and authorize PG&E to proceed with equitable and cost-effective incentive measures. While we reject the staff recommended contingency fund, we will use the staff figure of $8.5 million for this program in developing an overall conservation budget for PG&E. It is not clear that the market can absorb more than this at this time.

Energy Management
<u>Development Program</u>

The staff does not take exception to the various energy management programs, including colleges and universities, school plant analysis, and hospitals. It does recommend that a portion of the program funds be used for incentives which ECB believes will encourage the customer to take some action. ECB recommends that $232,000 of the colleges and universities program should be reserved for incentives, $309,000 of the school plant analysis program be reserved for incentives, and $223,000 of the hospital program be reserved for incentives. Energy Commission called for sharply increased expenditures here to make up for losses in federal assistance programs.

PG&E's exhibit indicated a substantial marketing component to this program despite the narrow market involved. We believe that the vital need of customers in this category to reduce energy costs coupled with the availability of incentives should permit PG&E to sharply reduce the promotional effort and still produce excellent results. Therefore, we will grant about 70% of the budget requested by PG&E for this category.

Technical Support
Programs

The staff supports PG&E's Technical Support Programs for demonstration/retrofit demonstration projects, C-I-A lighting analysis, applications for engineering, C-I-A energy conservation information center, and in-house energy conservation. The ECB recommends a disallowance of $565,000 for the Conservation Communications Support Program through the use of five man teams, elimination of self-audit workbooks, elimination of one market research, and half as many newsletter issues. The staff further recommends the reduction in C-I-A Awards Programs from $624,000 to $365,000; and a $313,000 reduction in C-I-A seminar programs for promotional items, display models, and additional support staff.

As discussed earlier, we eliminate the C-I-A Awards Program. We believe staff's support of demonstration retrofit projects, lighting analysis, and applications engineering is well justified. On the other hand, we see both duplication and promotion within the remaining Technical Support Programs. We therefore reduce the combined budget requests for those programs by one-half and will permit management to allocate the reductions among the programs.

Energy Commission's Conservation
Incentive Program Recommendations

The Energy Commission staff believes that PG&E failed to develop certain programs with significant savings to various market segments because its conservation potential analysis was incomplete. The Energy Commission staff therefore recommends that PG&E, when designing new conservation incentive programs, initially undertake a market research, confirm the conclusions of market research through a pilot program before full scale implementation of a program is made.

The Energy Commission staff believes that the following areas have potential for development of incentive programs:

1. Residential appliance program - especially the three programs proposed by Energy Commission for incentive payments for purchase of energy efficient refrigerators for residential retail customers as well as owners of residential rental buildings; the development of information on the energy efficient characteristics of used refrigerators and a market research on the types, number, and factors influencing such purchases; the expansion of Salesperson Incentive Programs; and modifications to Voluntary Builders Program.

2. Streetlighting conversion program.

3. Expansion of commercial incentives program from $13.2 million to $14.2 million in 1982 and from $17.5 million to $30 million in 1983.

Based on the Energy Commission staff's estimates, the additional revenue requirements, over and above PG&E's request, are $5.1 million in 1982 and $21.1 million in 1983 for these additional programs. In addition, the streetlighting conversion program will require substantial additional capital.

We do not believe that PG&E's programs should be arrested pending outcome of the various studies and procedures recommended by the Energy Commission. We believe that Energy Commission staff's comments are worthy of consideration by PG&E and to the extent such studies and programs can be feasibly incorporated into PG&E's proposed programs within the constraints of the authorized budget, PG&E should consider adoption of the Energy Commission staff's proposals. In keeping with the regulatory philosophy of this order, PG&E's management has the discretion to adopt those programs that will produce results.

Contingency Fund

PG&E considers the staff suggested contingency fund as being onerous and against the mutual objective of accelerating cost-effective conservation programs. We are disappointed in the results of our establishment of contingency funds for PG&E's conservation programs in D.91107. In particular, despite our emphasis on the importance of pursuing conservation in the multi-family and rental building area, PG&E did not expend the allocated funds in this area, and we are not pleased with its overall effort there. In addition, the current policy of requiring Commission approval for utility expenditures out of the contingency funds has led to Commission and staff involvement in the minor details of utility program management. We will discontinue this involvement and reject continued use of contingency funds.

B. Load Management Programs

Load management, which is defined as a strategy to affect time-related demand for energy, has played an increasingly important role in the supply planning of California utilities. As early as 1975, PG&E has initiated a variety of load management programs designed to shift peak demand through the use of incentives and direct load controls. In 1979 Energy Commission adopted a set of four load management standards in accordance with Section 25403.5 of the Public Resources Code.

PG&E has developed a 1982 test year budget for load management operating expense and capital expenditures of $58,578,000 ($21,061,000 operating expenses and $37,517,000 capital) for its Electric Department and $1,612,000 ($1,236,000 operating expenses and $376,000 capital) for its Gas Department. The staff has recommended a total of $43,426,000 for the Electric Department of which $19,497,000 is for operating expenses and $23,929,000 for capital expenditures. The staff further recommends that $3,997,000 of the recommended total for operating expenses and $8,754,000 of the recommended total for capital expenditures be placed in a contingency fund. For the Gas Department, the staff recommends total expenditures of $1,012,000 of which $646,000 is for operating expenses and $366,000 for capital with no contingency fund restrictions.

Although the staff recommends that PG&E's proposals should be generally supported, it recommends that certain projects be deferred from the 1982-1983 period or at least reduced in funding magnitude until further technical and financial evaluation are completed. The staff indicates that although it is recommending a 25% decrease in the requested budget, it still represents a 112% increase in 1982 expenditures over 1980. The staff indicates that it has attempted to set a balance between supporting all recommended programs when there is a possible MW savings versus the need to be prudent with ratepayer funds by recommending deferral or limitation of programs pending further development efforts. The staff further states that its recommended reduction, assuming no use of the contingency fund, will result in a 44% reduction in program costs with only a 6% reduction of PG&E's projected MW savings.

Table VIII-2 sets forth a comparison of the staff's and PG&E's recommended expenditures for load management for the Electric Department, and Table VIII-3 sets forth a comparison of load management expenditures for the Gas Department. The first page of Table VIII-2 indicates the issues in which there is substantial agreement between the staff and PG&E, and the second page of Table VIII-2 presents those areas at issue between staff and PG&E. The first six lines of page 2 of Table VIII-2 indicate that the staff recommends certain budgeted amounts be subject to contingency fund treatment, and in other cases that the budgeted amounts for various programs either be disallowed or authorized at a reduced level.

Table VIII-2

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
LOAD MANAGEMENT TOTAL EXPENDITURES
TEST YEAR 1982

(000'S OMITTED)

Line No.		Original as Filed (A)	PGandE Revised (B)	Staff Revised: Non-Contingency (C)	Staff Revised: Contingency Fund (D)	Staff Revised: Total (E)	Exceeds Staff (F)	Line No.
	Staff-PGandE Same							
	Residential							
1	Cold Storage	$ 50	$ 50	$ 50	$ 0	$ 50	$ 0	1
2	Energy Cost Indicator	50	50	50	0	50	0	2
	Agricultural							
3	TOU/Curtailable	3,623	3,623	3,521	0	3,521	102	3
	Commercial/Industrial							
4	TOU A-23/A-22/A-21	515	515	502	0	502	13	4
5	TOU A-20	387	387	378	0	378	9	5
6	Interruptible/Curtailable	75	75	75	0	75	0	6
7	Visual Display Metering	1,825	1,825	1,755	0	1,755	70	7
8	Group Load Curtailment	5,117	5,117	5,072	0	5,072	45	8
9	Energy Cost Computer	25	25	25	0	25	0	9
10	Auxiliary Power Services	50	50	50	0	50	0	10
11	Solar Monitoring	256	256	250	0	250	6	11
	General							
12	Cooperative Electricity Management	6,836	6,836	6,711	0	6,711	125	12
13	PURPA Metering	2,730	2,730	2,632	0	2,632	98	13
14	Marginal Cost/MC Rate Design	295	295	286	0	286	9	14
15	Metering of Substation/Transformer Sites	1,828	1,828	1,775	0	1,775	53	15
16	Demand Control Center	552	552	543	0	543	9	16
17	TOTAL SAME	$24,214	$24,214	$23,675	$ 0	$23,675	$ 539	17

Table VIII-2 (Contd.)

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
LOAD MANAGEMENT TOTAL EXPENDITURES
TEST YEAR 1982

(000'S OMITTED)

Line No.		PGandE Original as Filed (A)	PGandE Revised (B)	Staff Revised: Non-Contingency (C)	Staff Revised: Contingency Fund (D)	Staff Revised: Total (E)	PGandE Exceeds Staff (F)	Line No.
	ISSUES							
	Staff Recommended Contingency Fund							
1	Residential Deferrable Service	$ 744	$ 744	$ 0	$ 744	$ 744	$ 0	1
	General							
2	Energy End-use Data Collection, Analysis, and Forecasting	1,270	1,270	398	770	1,168	102	2
3	Metering of Small Power Producers	417	417	0	417	417	0	3
4	Load Research for Conservation Monitoring and Evaluation	5,581	5,581	2,086	3,381	5,467	114	4
5	LM Reserve Fund	1,500	1,500	0	1,500	1,500	0	5
6	Subtotal	9,512	9,512	2,484	6,812	9,296	216	6
	Staff Recommends Reduced Funding/Use of Contingency Fund							
7	Residential Peak Load Reduction	9,267	9,267	1,395	5,939	7,334	1,933	7
8	Subtotal	9,267	9,267	1,395	5,939	7,334	1,933	8
	Staff Recommends Reduced or Zero Funding							
	Residential							
9	TOU Rates	4,878	4,878	905	0	905	3,973	9
10	Telephone LM System	1,086	1,086	210	0	210	876	10
11	Radio LM System	332	332	59	0	59	273	11
12	Programmable Service	1,974	1,974	194	0	194	1,780	12
13	Smart Duty	1,062	1,062	104	0	104	958	13
	Commercial							
14	A/C Load Deferral Experiment	5,193	5,193	1,257	0	1,257	3,936	14
15	Programmable Controller	1,060	1,060	392	0	392	668	15
16	Subtotal	15,585	15,585	3,121	0	3,121	12,464	16
17	TOTAL ISSUE	34,364	34,364	7,000	12,751	19,751	14,613	17
18	GRAND TOTAL	$58,578	$58,578	$20,675	$12,751	$43,426	$15,152	18

Table VIII-3

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEPARTMENT
LOAD MANAGEMENT TOTAL EXPENDITURES
TEST YEAR 1982

TABLE 4

(000'S OMITTED)

Line No.		PGandE Original as Filed (A)	PGandE Revised (B)	Staff Revised: Non-Contingency (C)	Staff Revised: Contingency Fund (D)	Staff Revised: Total (E)	PGandE Exceeds Staff (F)	Line No.
	Staff-PGandE Same							
1	Residential Solar Monitoring	$ 132	$ 132	$ 130	$ 0	$ 130	$ 2	1
2	Load Research - End-Use	464	464	453	0	453	11	2
3	Total Same	596	596	583	0	583	13	3
	Issues							
4	Energy End-Use Data Collection, Analysis, and Forecasting	847	847	389	0	389	458	4
5	Marginal Cost	169	169	40	0	40	129	5
6	Total Issue	1,016	1,016	429	0	429	587	6
	GRAND TOTAL	$ 1,612	$ 1,612	$ 1,012	$ 0	$ 1,012	$ 600	7

Gas Load Management

The staff's gas load management program of $1,012,000 is $600,000 less than PG&E's estimate of $1,612,000. The major area of difference is the staff's disallowance of $458,000 for energy end-use data work and $129,000 for marginal cost studies. The staff believes that the rapid increase in these categories will not be required in the future.

Energy Commission's Position

Energy Commission supports the funding request of PG&E for load management programs and opposes staff's alternatives, including the contingency fund recommendation. Regarding mandated load management programs, Energy Commission notes that it has a specific legislative mandate to study and implement cost-effective load management programs. Energy Commission points out it has conducted extensive studies and public hearings and that the mandatory load management programs were found cost-effective, and formally adopted by the Energy Commission. It relies on Public Resources Code Section 25403.5 in its contention that this Commission is required to authorize funding of the mandated programs. Section 25403.5 provides that "any expense of capital investment required of a utility by the standards shall be an allowable expense or allowable item in the utility rate base and shall be treated by the PUC as such in a rate proceeding".

Energy Commission also supports PG&E's request to expand the residential load cycling program by 30,000 cyclers, a proposal opposed by staff. Energy Commission noted significant flaws in staff's cost-effectiveness analysis of the cycler program and further rejects staff's claims that the technology is still not proven. In the words of Energy Commission's witness Dhar, "The Detroit Edison's water heater program, which allows almost 200MW of demand reduction, has been in operation for 40 years."

Energy Commission also argues that the staff proposal for contingency fund financing frustrates the legislatively determined goal to achieve an 8% penetration of residential air-conditioning units. Energy Commission also believes that the contingency fund will reduce flexibility and create budgetary uncertainties. Energy Commission further supports PG&E's expenditures for end-use data collection, PURPA, meters, and load research. Energy Commission states that contrary to staff testimony, the level of data collection envisioned by Energy Commission for utilities is expected to increase rather than decrease.

Discussion and Conclusion

We believe that PG&E has undertaken a vigorous and promising load management program which will help improve overall system reliability. On the other hand, we believe some belt tightening is in order. As noted in our discussion at the beginning of Section VIII, we have approved a budget of $47,574,000 in this area. We have also rejected the use of a contingency fund for reasons discussed earlier. We will await with interest the results of the authorized experimental and demonstration programs and are prepared to entertain proposals for the prompt expansion of thos load management programs for which broad implementaion is shown to be cost-effective.

C. Cost-Effectiveness Analysis of Energy Conservation Programs and Load Management Programs

PG&E's witness L. Baldwin testified on the cost-effectiveness analysis of energy conservation programs, load management programs, and also on cogeneration pricing. Witness Baldwin testified that while it is desirable to conserve scarce resources, it is important to compare the benefits of reduced consumption with the costs of achieving this reduction. The purpose of cost-effectiveness analysis is to perform this comparison and thereby facilitate the selection of an appropriate mix of conservation programs and generation alternatives. In determining cost-effectiveness, there are four perspectives from which it should be reviewed: society as a whole, the utility, the program participants, and PG&E's ratepayers. From all four perspectives, benefits are calculated as costs avoided due to reduced energy consumption directly attributable to the program.

The witness made calculations from a utility, society, and participant perspective of the combined electric programs and combined gas programs and concluded in each case that the cost per unit of life-cycle energy savings is less than the corresponding avoided cost and, therefore, they were cost-effective. In calculating the cost-effectiveness of conservation programs from a ratepayer's perspective, many assumptions about future rate schedules must be made, therefore, the results of these calculations are uncertain. E. Heim testified on the cost-effectiveness of customer-related conservation programs.

PG&E's load management cost-effectiveness analyses are considered preliminary results since the bulk of PG&E's load management programs have not achieved full scale. PG&E considers load management planning to be an iterative process requiring continual recalculations on the cost-effectiveness of its load management program. In addition to capacity and energy benefits which result from load management programs, certain programs may also yield operational benefits. In addition to these benefits, load management programs may provide other societal benefits such as environmental, safety, noise reduction, and reduced consumption of oil and natural gas which have not been quantified in their analysis. Witness Baldwin concludes that taken as a whole PG&E's proposed load management programs are estimated to be cost-effective. For programs directed at each class of customers, benefits to society as a result of PG&E's proposed investments will also exceed societal costs. PG&E's residential load management programs are estimated to yield $2.06 in societal benefits for every dollar of societal cost and commercial-industrial programs are expected to be even more cost-effective to society with a combined benefit cost ratio of 10.02.

<u>Conservation and Load Management Conclusion</u>

In conclusion, we reiterate that we have granted management substantial discretion to reallocate funds within the conservation budget to improve performance. Table VIII-5 shows a detailed breakdown of the conservation budget by departments. The following summarizes the approved overall conservation and load management budget.

TABLE VIII-4
(000s Omitted)

	Electric	Gas	Total
Residential conservation including home appliance and community services	$ 5,998	$ 4,884	$10,882
C-I-A	20,695	10,272	30,967
Conservation Evaluation	550	550	1,100
Subtotal Conservation	27,243	15,706	42,949
Load Management	46,541	1,033	47,574
Total Conservation and Load Management	$73,784	$16,739	$90,523

TABLE VIII-5

PACIFIC GAS AND ELECTRIC COMPANY

Customer-Related Conservation Programs
Included In Rates

Test Year 1982
(000's omitted)

	Electric	Gas	Total
RCS Programs			
General Customer Inquiries	$ 1,008	$ 792	$ 1,800
Homes, Appliances & Systems			
Voluntary Builder	1,034	866	1,900
Master Meter Conversion	210	177	387
Salesperson Incentive & Appliance Efficiency Mktg.	2,285	1,589	3,874
Subtotal	3,529	2,632	6,161
Community Services			
Community Cooperative	86	86	172
Div. Conserv. Rep.	831	831	1,662
Stockton Training Center	544	543	1,087
Subtotal	1,461	1,460	2,921
Total RCS, Home & Community	5,998	4,884	10,882
C-I-A			
Audit Programs			
C-I-A EUA	4,782	2,578	7,360
Comp. Audit	2,758	1,483	4,241
Agricul. Irrig. Serv.	1,883		1,883
Load Mgmt. - Incentives	5,251	3,249	8,500
Subtotal	15,149	7,331	21,984
Energy Mgmt. Develop. Program Incl. College, School & Hosp.	3,744	1,928	5,672
Technical Support			
Demo/Retro	354	182	536
Lighting	266		266
Appl. Engr.	530	273	803
C-I-A - Energy Info.	248	128	376
In-House Conserv.	41	21	62
C-I-A Communication	427	219	646
C-I-A Seminars	411	211	622
Subtotal Technical Support	2,277	1,034	3,311
Total C-I-A	20,695	10,272	30,967
Conservation Evaluation	550	550	1,100
Total Customer-Related Conserv.	27,243	15,706	42,949

To assure that the general direction of conservation and load management programs is maintained as approved, we instruct PG&E not to reallocate funds among the three major categories of Residential, C-I-A, and Load Management. Within each of these categories, management shall have the discretion to reallocate amounts up to $2,500,000 from a given program to be used in another existing or new program. Budget adjustments in excess of $2,500,000 should be made the subject of an advice letter filing.

Program Evaluation

PG&E's estimate for test year 1982 of $1,100,000 is $800,000 lower than the staff's estimate of $1,900,000. The staff allowance includes funding for various additional quantification studies the staff recommends be made by PG&E in 1982 and 1983. The studies recommended by the staff are: further studies on conservation potential with emphasis on short-term potential through 1985, program goals and customer response rates, savings per activity estimate, conservation buildup and persistence, and cost-effectiveness ratios.

Energy Commission offered its witness Khalsa to testify on its concern with conservation quantifications. Energy Commission claims that improved conservation quantification techniques can translate into an alternative portrayal of what PG&E ought to be doing, i.e., programs significantly different than what is indicated by A. D. Little (ADL) or what PG&E proposes to do during the next two years. Energy Commission's staff recommends a methodology and a schedule of compliance for PG&E to upgrade its conservation quantification efforts as part of an integrated system of energy conservation and supply planning.

Energy Commission argues that PG&E requires detailed guidance from the Commission before it is asked to undertake further conservation potential analysis. Energy Commission argues that considering the time and expense lost through the ADL effort, implementation of an integrated plan in one massive effort is not appropriate. Energy Commission's witness Khalsa sets forth in Exhibit 130, Chapter VII, his recommendations for PG&E in revising its conservation program planning.

The staff suggests that although there are similarities between Energy Commission's and the staff's criticism of PG&E's quantification evaluation program, it would probably be necessary for the Commission to choose one over the other to avoid burdening PG&E with excessive research obligations. The staff suggests that the Commission adopt the staff's recommendation for further studies on conservation potential, goals and customer response rates, savings per activity estimates, conservation buildup and persistence, and cost-effectiveness ratios. In addition, the staff recommends that PG&E in carrying out the required studies give maximum feasible attention to the residence appliance markets which were the subject of much of the Energy Commission's analysis and to the techniques of market segmentation analysis and marginal cost equalization so emphasized by the Energy Commission.

In response to the various recommendations made by both the Energy Commission and the staff for various studies, PG&E's witness Heim suggested six steps for establishing a sensible energy conservation evaluation policy.

1. The Commission and Energy Commission must agree upon and establish statewide conservation evaluation objectives and delineate priorities for these objectives.

2. To ascertain what progress has been made in attaining these objectives, the Commission and Energy Commission should jointly specify what further information is needed, why the information is needed, and when the information is needed.

3. The Commission must then provide adequate funding for the studies and activities necessary to address these conservation evaluation objectives. Adequate funding should be assured by a contingency fund.

4. The Commission should authorize PG&E to submit an action plan which would address how PG&E plans to meet the conservation evaluation objectives defined by the Commission and Energy Commission, and what its costs and time requirements would be. This action plan would specify PG&E's information priorities and the rationale for these priorities. PG&E would determine how the objectives would be addressed, how the data would be collected and analyzed, and the timing and cost requirements. If PG&E should determine that a given objective could be better addressed through cooperative efforts with other utilities, then its proposed action plan would recommend such joint action.

5. PG&E would consult and cooperate with both the Commission's ECB and Energy Commission's Conservation Section in developing and implementing its action plan. Workshops could be held to resolve any disputes and to formulate policy.

6. A cost/benefit procedure should be developed to compare the relative costs of conservation evaluation with the benefits associated with increases in accuracy of measurement.

Although the Energy Commission indicated little agreement with Heim's proposals, Khalsa did agree that the methodology he has recommended probably should be applied to all utilities. Staff witness Danforth agreed that workshops tied to an OII would be an excellent vehicle to determine statewide conservation evaluation objectives.

In D.91107 we placed much emphasis on several studies that PG&E was ordered to complete. These studies were to evaluate both the potential for conservation in all sectors and the most cost-effective ways to reach effective market saturation of achieveable conservation measures by 1985. They were also designed to feed into PG&E's conservation goal-setting process. The apparent deficiencies in the ADL studies submitted by PG&E, as well as disagreements between PG&E, staff, and Energy Commission about what should be sought in additional remedial studies disturbs us. We are also concerned that these studies do not seem to be tied to goal-setting as we had discussed in our previous order. This leads us to conclude that the path of continued studies may not be the most productive way to proceed. We also find substantial merit in PG&E's recommendation to use publicly noticed but informal workshops to resolve basic differences in evaluation methodologies.

While the Energy Commission indicates the need for immediate studies, we agree with PG&E that while the various programs being considered may not be the most cost-effective, they are, nonetheless, cost-effective. All parties have agreed that PG&E has been the acknowledged leader in the field of conservation. Rather than delay PG&E's programs at this time, we believe it is proper to permit PG&E to proceed with its conservation programs with the modifications previously described, including program evaluation studies at the company's proposed budget level of $1.1 million per year. At the same time, we are obliged to adopt an evaluation process to improve accountability for the performance of conservation programs.

On the one hand, we are concerned about PG&E's efforts to attribute almost all conservation that occurs in its service area to its programs. PG&E has not persuaded us on this point. On the other hand, we are equally concerned by the well intentioned efforts of staff and Energy Commission analysts to distinguish those conservation results produced by PG&E from those generated in the marketplace alone. While we see the theoretical value to this analysis, we doubt that the results will be acceptable as a basis of regulatory action.

Consequently, we adopt an approach to evaluation that minimizes the need for theoretical studies and relies on the basics. First, we believe that conservation flowing from behavorial changes should not be considered a product of PG&E's programs. Particularly in light of our restrictions on general conservation advertising and reduction of conservation advertising and promotional budgets, we are convinced that this type of conservation is primarily a result of market forces.

Second, conservation resulting from hardware or process changes should be considered the product of PG&E's programs only when PG&E can demonstrate that one of its programs was employed by the customer either in determining the need for or in implementing the conservation measures. For example, use of a ZIP loan demonstrates that the customer employed its program in implementing specific conservation measures. Even though market forces may have had a singificant impact in the conservation decision, we shall assume that the ZIP loan, in essence, closed the deal. Another example would be the use of a commercial EUA. When PG&E calls back to determine which recommended measures were undertaken, we shall assume that the customer employed the audit to determine the need for the conservation measures which were implemented. On the other hand, we would be hard pressed to attribute a specific amount of conservation to exhibits PG&E may offer at fairs. Only if sign-ups for other programs subsequently lead to conservation measures could we conclude that PG&E's program was employed by a customer.

To resolve any uncertainties relating to this evaluation methodology for use in future rate proceedings, we shall adopt PG&E's proposal to hold publicly noticed workshops. These workshops shall be held February 4 and 5, 1982. Uncertainties not resolved in the workshops may be raised in the supplementary hearings discussed below.

Conservation Incentives

The record in this proceeding contains a discussion of the use of financial incentives to encourage PG&E to expand its promotion of cost-effective energy conservation investments. We think it probable that such an incentive scheme would stimulate greater efficiency and productivity in PG&E's conservation programs. For unregulated companies, the discipline of the marketplace is the ultimate incentive to improve productivity. Greater productivity produces greater profits; inefficiency erodes profits. PG&E, as a regulated company, does not face these stresses of the marketplace. Yet it appears that wise policy may be to create a regulatory environment approximating that of the free market.

It is important that we continue to strengthen the accountability of the company for its conservation expenditures. It appears that the most effective way to assure accountability, particularly in a period of budget constraints for agencies such as this Commission, may be to make management accountable to its own shareholders. We have granted management a specific budget for conservation programs, and have granted management broad discretion in allocating funds among programs. We adopted an approach to evaluation that will require the company to demonstrate specific savings from specific programs.

The final link in making management accountable may be to adjust earnings based on actual performance. Management must then account to its shareholders why earnings are reduced if performance is inadequate. Management may also generate increased earnings for the shareholders if superior performance is achieved.

Additional earnings generated in this manner are justified due to the great value to the ratepayers of cost-effective conservation. Conservation will reduce dependence on foreign oil, increase national security, improve the national balance of payments, reduce pollution, increase jobs in the domestic energy and conservation equipment sector, increase the rate at which utilities can increase energy supplies in the short term and reduce inflationary pressures.

On the other hand, the company's earnings may be reduced for poor performance of conservation programs. This provides reasonable assurance to the ratepayers that the company will implement conservation programs in the most effective manner.

As long as PG&E's conservation programs, including any incentives to participating ratepayers or the utility, remain cost-effective compared to supply alternatives, ratepayers could benefit directly from expansions in conservation efforts. This is particularly so when incentives induce more savings from the same level of expenditures by encouraging more efficient use of utility money budgeted to conservation. This Commission has long noted that the ratepayers benefit whenever a therm or kilowatt-hour is saved for less than it would cost to purchase and consume it. This rationale applies equally well to savings engendered by incentives to the utilities.

In this proceeding the Energy Commission has proposed an incentive program to encourage the attainment of certain alternative energy and conservation goals by PG&E. These proposals were well explored in the record but focused primarily on alternative resources. There was no discussion of a comprehensive conservation incentive plan.

Although the record in this proceeding is inadequate, past Commission decisions and ongoing utility incentive programs do provide some guidance. In D.84902, we stated that we would evaluate the utilities' return on the basis of the vigor, imagination, and effectiveness of their conservation programs. Our staff and other interested parties have studied many methods to implement this policy in the ensuing six years. We have found that this broad policy directive has provided insufficient guidance to the companies, and has been difficult to implement without our current procedural framework.

In D.92714, we adopted a procedure to adjust SoCal's earnings based on conservation performance. This procedure establishes a target of energy savings to be achieved by the utility's conservation programs. Performance within a "dead band" bracketing the target would not trigger an earnings adjustment. Performance above or below the dead band would trigger a positive or negative adjustment, calculated under a fixed dollars-per-energy-saved schedule. Ratepayers would thus pay out or be refunded money only for exceptionally good or poor program performances, which would either have captured or lost exceptionally large potential benefits.

A similar procedure, based on a dead band, was adopted in another context in D.93363, to adjust Southern California Edison Company's earnings based on the performance of two large coal-fired generating stations.

We note that our staff proposed an earnings adjustment procedure for conservation in the SDG&E rate proceeding (A.59788) which we also decide today. That proposal has also been rejected for lack of an adequate record.

The procedure we propose today presents the elements that now appear necessary to design a cost-effective conservation incentives program. Today's proposal is a refinement of the SoCal conservation incentives procedure. The refinements are intended to identify more clearly which savings can be included in the evaluation and to assure greater accountability for the company's programs. It is presented here as a focus for the hearings to follow; all numerical estimates and procedural elements are subject to change.

We stress that this proposal presents only one possible mechanism for providing conservation incentives to utilities which should be tested through public hearings. As with any proposal, it would undoubtedly benefit from further refinement and the correction of weaknesses. It may not be the only, nor perhaps the best, alternative to reaching our goal of furthering cost-effective conservation.

We therefore urge any party to this case who is interested in conservation incentives to review and comment on this proposal, analyzing its strengths and weaknesses, suggesting refinements or other modifications, and/or presenting partial or complete alternatives to it. This will allow us to develop the thorough record necessary to determine whether such a procedure should be adopted, and if so, to ensure that the one we do adopt is sound.

We will continue this proceeding for the narrow purpose of investigating the feasibility of a conservation incentives program. Interested parties shall file their comments in the form of prepared testimony no later than February 1, 1981. The hearings will commence on February 16, and shall be limited to specific facts, analysis, and policy questions raised in the prepared testimony, and to questions of evaluation of conservation savings not resolved in the preceding workshops.

Parties may also submit comments, similar to those we have invited above, on the Energy Commission proposal to establish incentives based on penetration of the ZIP program in low income and renter markets. Overall, these hearings will allow us to develop a thorough record through which to analyze the appropriateness of conservation incentive proposals, as well as the specific proposal which is described below.

PROPOSED PROCEDURE TO ADJUST EARNINGS FOR CONSERVATION PERFORMANCE

* Establish conservation targets for 1982.

In this proceeding, PG&E projected that its proposed conservation programs and budget would generate lifecycle savings of 4.1 billion kWh and 957 million therms. After eliminating savings attributed by PG&E to the ZIP and RCS programs (which are the subject of a separate decision) and those attributed to programs recommended for reduction or elimination in this decision, projected savings for PG&E's adopted conservation program are 2.4 billion kWh and 335.1 million therms, on a lifecycle basis. We propose these conservation levels as the 1982 targets.

We note that not all conservation estimated by the company in A.60153 would generate conservation earnings under this proposal. Many programs may not produce measurable, tangible conservation under our evaluation methodology. We expect this will encourage management to focus resources on those programs that permit clear evaluation of the company's performance.

* Establish a "dead band" around the targets.

The conservation targets should be at the center of a dead band within which no earnings adjustments would be made. We propose to establish a dead band of 5% above or below the targets.

* Establish a schedule of earnings adjustments.

If the company demonstrates conservation results within the dead band for gas or electric savings, no adjustment should be made for either gas or electric earnings. If the company is unable to demonstrate performance to the lower limit of the dead band, earnings should be reduced in two ways. Gas earnings should be reduced by $750,000 plus an additional 85 mills for each therm below the lower limit of the dead band. Electric earnings should be reduced by $750,000 plus an additional 12 mills for each kWh below the lower limit of the dead band. If the company is able to demonstrate conservation performance above the upper limit of a dead band, earnings should be increased in like amounts.

The earnings adjustments of $750,000 at either end of the dead bands recognize success or failure of the programs in achieving minimum expectations. This adjustment is made at approximately one-half the amount of earnings adjustments outside the dead band. The electric earnings adjustment outside the dead band is intended to meet the so-called non-participant of cost-effectiveness. Approaching deregulation of natural gas prices renders this test inapplicable to gas conservation programs. The gas earnings adjustment outside the dead band has, therefore, been kept to approximately 10% of current marginal costs. Compared to current estimates, the gas earnings adjustment is about 5% of the cost of gas to be delivered by increasingly costly Alaska Natural Gas Transportation System.

* <u>Establish a maximum level for the adjustment</u>.

We would limit the potential exposure of ratepayers and the utility during the initial year of operation by limiting the total size of the adjustment. We propose to adjust PG&E's earnings by no more than $10 million up or down based on 1982 performance. The level and desirability of ceilings in future years should be discussed by the parties

* <u>Provide for annual review</u>

We propose to adjust earnings for conservation performance in the annual Conservation Financing Adjustment (CFA) proceeding. The company's CFA application should include savings attributable to the company's programs developed in accordance with the evaluation methodology dismissed herein a calculation of any earninzs adjustment that is in order.

IX. Miscellaneous

A. System Efficiency Research and Energy Production

1. Conservation Voltage Regulation (CVR)

The CVR program is an energy conservation program which saves electricity by reducing customer service voltages. Under CVR the maximum allowable customer service voltage is reduced from 126 volts to 120 volts, or as far as possible while maintaining a minimum voltage of 114 volts. This reduction in service voltage results in reduced electricity consumption by the customer.

The CVR program is being implemented in two phases. Phase I consisted of a reduction in the maximum voltage from 126 volts to 122 volts or as low as possible while maintaining the 114 volts minimum. This reduction was accomplished without significant capital investment by making adjustments to voltage regulation equipment wherever possible. Phase II consisted of reducing the maximum voltage levels beyond what was accomplished under Phase I by implementing capital improvement as necessary wherever it is cost-effective to do so. The goal of Phase II is a maximum voltage of 120 volts.

Subsequent to PG&E's initial filing, and as a result of cooperative efforts of both PG&E and the ECB, substantial progress has been made. Substantial opportunities for Phase II construction in the test year have been identified. As a result of these cooperative efforts, the ECB concluded that a rate of return penalty for CVR is unnecessary and would, in fact, be counterproductive. The ECB, therefore, recommends that PG&E's requested expenditures of $866,000 for the test year be approved. It also recommends that PG&E be allowed an additional $5,500,000 in capital expenditures for Phase II construction. This amounts to a $2,750,000 increase in rate base on a simple average basis. PG&E also proposed a minor change in Electric Rule No. 2 c 1 to which the staff concurred.

TURN in its brief expresses concern that PG&E has failed to consider the use of tapped distribution service transformers among the list of possible Phase II hardware changes, and the general reluctance of PG&E to expand CVR to its full cost-effective level. TURN suggests that this Commission order PG&E to include the use of such tapped distribution service transformers in its CVR Phase II and Phase III studies. The record in this proceeding does not support ordering PG&E to undertake such a study, however, we will expect PG&E to respond on why such tapped distribution service transformers should or should not be used in the next general rate proceeding.

Similarly, TURN in its brief argues that it is concerned about PG&E's apparent reluctance to expand CVR and the 21 KV conversion program to the limit of cost-effectiveness. TURN argues that supply side conservation measures such as CVR and 21 KV can produce energy savings with a much greater assurance than customer-oriented conservation efforts and, therefore, should be the first programs expanded to the margin of cost-effectiveness. PG&E argues that it is already committed to full-scale 21 KV conversion. However, such conversions are costly and must compete with other programs of higher priority such as service to new customers or relieving overloads. We are satisfied that PG&E's CVR program, as revised, and 21 KV conversion programs are progressing in a satisfactory and orderly manner.

PG&E was ordered by D.92931 to report on the voltage levels in the Monte Rio and Guerneville areas since December 1978 in dismissing a complaint case. The report indicated three unrelated periods of overvoltage. PG&E's witness testified that none of the problems of overvoltages was the result of the CVR program.

Mr. Erickson, a complainant in Case (C.) 10930, testified that he had no problems with voltage levels since May 1980. We are satisfied that the overvoltage problems in the Monte Rio and Guerneville areas have been corrected and were not attributable to the CVR Program.

2. Cogeneration and Small Power Production

In D.91107 the Commission assessed a 20-basis point penalty on the Electric Department's return on common equity for PG&E's failure to aggressively pursue cogeneration projects. In this proceeding PG&E's witness Meyer testified that from January 1, 1980 through June 1981, PG&E has signed contracts to obtain 246.1 MW of power from cogeneration and solid waste projects. It has also signed two contracts to purchase 380 MW of wind energy on top of the 14 previously executed contracts to purchase 160.4 KW of wind energy. During February and June 1981, PG&E has contracted to purchase 53.5 MW from four hydroelectric plants on top of the two previous contracts to purchase 160 KW of hydroelectric power. These achievements fall significantly short of the 600 MW of new cogeneration capacity the Commission required for elimination of the penalty in D.91107. However, they do exceed 600 MW of new generation capacity in resources this Commission has sought to expedite.

PG&E states that other indications of the comprehensiveness of PG&E's program and its good faith in encouraging cogeneration are:

1. The financial analysis of computer program (Exhibit 140) enables a prospective cogenerator to provide its own confidential financial data and related information and for a nominal cost (less than $70) be provided a financial analysis of cogeneration alternatives. The program is sufficiently flexible to provide financial analysis, assuming a variety of mixes of investment resources, including PG&E's equity.

2. The Environmental Regulations Assistance Program is being distributed and will advise prospective cogenerators of environmental regulations and permit requirements.

3. In D.92792, over opposition by staff and third parties, the Commission adopted PG&E's proposal authorizing an incentive gas rate for cogeneration.

4. Actively supporting amendments to the Fuel Use Act to simplify the use of fossil fuels for cogeneration facilities.

5. Increasing its cogeneration and small power production staff to adequately implement its comprehensive programs.

6. Retaining Resource Planning Associates (RPA) to estimate the cogeneration potential within its service area. Staff described the RPA study, distributed in January 1981 as "reasonably comprehensive" and the "best" done recently on cogeneration potential within PG&E's service area.

7. Further encouraging thermally enhanced oil recovery cogeneration projects (and thereby seeking to add to the 66 MW already contracted for) by, among other actions, retaining a consultant to identify further oil field cogeneration projects and establishing an Oil Field Task Force to coordinate companywide efforts on oil field recovery projects.

8. Investigating alternatives to the residential cogeneration feasibility studies. PG&E is prepared to proceed with the implementation of a demonstration project using natural gas-fueled engines.

9. Including in its resource plan through 1992, 661 MW of cogeneration and solid waste resources. This, however, does not represent an upper limit. As additional projects become more economically and financially feasible, they will be added.

10. Encouraging cogenerators and small power producers to enter into contracts pending a final determination in OIR 2 by offering to modify, at the discretion of the cogenerator, previously executed contracts to incorporate any new contract deemed appropriate by the OIR 2 decision.

11. Providing prospective cogenerators price offerings, contract forms, interconnection guidelines, and other information necessary to encourage cogeneration. Staff further found that PG&E has "enthusiastically offered to process cogeneration applications, answer inquiries, and...negotiate cogeneration contracts."

12. Immediately and positively responding to the recommendations for further action proposed by staff's direct testimony.

The staff witness Flaherty testified that PG&E's performance has been adequate in encouraging cogeneration projects during 1980 and that this performance has continued into 1981 at an enhanced level. In reviewing PG&E's program in persuading potential cogenerators to sign contracts, the staff witness believes it is necessary to consider the major hurdles confronting cogeneration activities. Of the six hurdles listed by staff, PG&E has control only over the first category. The six hurdles are:

1. The cooperation of PG&E in presenting price offers, standard contracts, technical assistance in matters such as interconnection, and also the willingness to negotiate alternate contract terms when desired by the prospective cogenerator.

2. Governmental rules and regulations which the prospective cogenerator must comply with (local, state, and federal).

3. Financial viability. The cogeneration activity must be attractive financially for a decision to cogenerate to be made. This usually means that the potential cogeneration activity must show promise of a very short payback, as short as three years or less.

4. Concern that prices paid for generated electricity and the cogenerator's fuel costs (e.g., gas or oil) will change differently and adversely with time.

5. Competition with PG&E's principal product lines for financial and other corporate resources.

6. Cogeneration project capital requirements are quite large in proportion to the firm's annual capital budget.

Since the issuance of D.91107, the staff observed that a number of significant changes have occurred which may have the undesirable effect of slowing the decision-making process of potential cogenerators and small power producers. These factors include: (1) the uncertain future of Federal Fuel Use Act restrictions on power plant use of natural gas; (2) impending changes of rules and possibly prices in the Commission's OIR 2 proceeding; (3) possible improvements in federal tax treatment of capital plant expenditures; (4) possible relaxation of environmental restrictions; and (5) the exceptionally high level of interest rates during the past year.

Based on the above reasons and PG&E's encouraging performance in 1980 and 1981, staff witness Flaherty recommended that the 20 basis point penalty on common equity be discontinued.

Energy Commission's witness J. Helmich presented his evaluation of PG&E's cogeneration program. Although Energy Commission's staff finds PG&E's performance, though improved, substantially less effective that it should be, Energy Commission's staff believes that the major deficiency in the PG&E program is the lack of willingness on PG&E's part to enter into an equity position on economically feasible cogeneration projects. In order to correct this reluctance on PG&E's part to invest its capital on cogeneration projects the Energy Commission staff offers the following recommendations:

1. The Commission maintain the 20 basis point penalty because of PG&E's unsatisfactory performance in signing up new cogenerators and that it be removed only upon signing 100 MW of new contracts with equity investment or joint ownership by PG&E. This coupled with the incentives and penalties in Marcus' testimony should provide adequate incentives for PG&E equity ownership.

2. Along with the activities which PG&E currently has underway to encourage private development of cogeneration, PG&E should aggressively invest its capital in cogeneration projects.

3. PG&E be required to offer this equity capital and joint financing of projects assistance in a mailing "to the chief executive officers of identified potential cogenerators."

4. PG&E's financial analysis model should be modified to accept flexible capital arrangements between it and the industry rather than solely private capital investment.

Although PG&E has reduced the level of cogeneration projects in its latest resource plan, PG&E contends that such action was necessary in view of its deteriorating financial situation. PG&E's witness Doudiet testified in rebuttal that if PG&E's financial health is restored, it is willing to proceed with cost-effective cogeneration projects requiring PG&E funds. We agree with staff that considering the many unexpected problems relating to cogeneration, PG&E's performance has not been unreasonable, particularly in light of its development of wind and small hydro resources. We will therefore not renew the cogeneration penalty. PG&E has lost $14.4 million which will never be recovered. In the event of poor performance in this critical area of enhanced reliability and efficiency, the Commission will again consider a penalty.

We shall require PG&E to file within 75 days a plan to expedite development of cogeneration in its service area. This plan should include techniques to overcome the barriers to more rapid implementation of cogeneration noted by PG&E during this proceeding. PG&E is currently required to file quarterly reports of cogeneration progress with this Commission. We shall require PG&E in its reports due May 1, 1982 and November 1, 1982, to show cause why a cogeneration penalty should not be reinstated.

3. RD&D

Because of the Commission's interest in RD&D activities. PG&E filed Exhibits 9 and 142, and the staff similarly presented two witnesses who testified on this subject matter. Energy Commission also offered its comments on PG&E's RD&D program.

The staff expressed its concern that PG&E has not given high enough priority in the past to RD&D related to renewable and alternative resources especially in light of the emphasis PG&E placed on such resources in its December resource plan. Staff witness Joshi proposed a system of weighted criteria for use in establishing priorities for RD&D. He also recommends that PG&E establish a system of RD&D program evaluation; exclude normal engineering, environmental data gathering, business data processing, and siting studies from its RD&D report; PG&E representatives on EPRI work to allocate more EPRI funding on conservation-related research; PG&E should aggressively seek cosponsors and government funding.

Staff witnesses C. Waddell and R. Joshi were critical of PG&E's management of its RD&D program and its failure to correct the deficiencies pointed out in the CMP management report. They were also critical of PG&E's overbroad definition of RD&D.

PG&E does not disagree that its management structure for RD&D needs revision. It has reacted to concerns raised by the CMP report by the creation of a RD&D management study in June 1981. Under this revised setup, PG&E's RD&D efforts will be centralized within its Department of Engineering Research. PG&E believes that refinement of the definition of RD&D and improvements in RD&D reporting are best accomplished by further informal communications between staff and PG&E.

We do not agree that informal communication will suffice. The Commission is deeply concerned by ongoing evidence, most recently reconfirmed by the record in this proceeding, that PG&E's planning and management of RD&D lack direction and a sense of priorities. Concrete steps must now be taken to ensure that the utility's RD&D program is more than a grab bag of disjointed projects.

PG&E is required by D-92940 in OII 80 to submit annual reports to the Commission, describing its response to criticisms contained in the CMP report. The next report is due on March 1, 1982. PG&E will be required to set forth in particular detail PG&E's program and management responses to the CMP report's criticisms of RD&D (CMP report at V-12 to V-13), and to provide copies of the RD&D portion to participants in the workshop described below.

We concur with witness Waddell that PG&E's definition of RD&D is inappropriate and inconsistent with that of the other utilities but we do not believe it would meaningful to attempt to arrive at a insufficiently developed definition of RD&D in this proceeding where it is impossible to devote the necessary time to fully explore the problems raised by the various parties on this issue. We further concur with recommendations made by our staff and that of the Energy Commission regarding the need for PG&E to give highest priority to renewable and alternative resources in its RD&D planning. Witness Joshi's proposed RD&D priority system is a laudable first attempt to synthesize important competing considerations.

In order to resolve these concerns, we will require staff, PG&E and other utilities to participate in a workshop to which the Energy Commission staff is invited. After the workshop, participants will recommend to the Commission appropriate revisions to the definition of RD&D and a system for setting RD&D priorities. We expect these recommendations within four months after the effective date of this order.

In the interim, PG&E will apply the following staff-developed guidelines when evaluating potential RD&D projects:

A. The project should support the RD&D objectives of the utility and the Commission. The utility must comply with the then existing environmental regulations.

B. The project should lead to environmental improvement and/or increase safety.

C. The project should support the Commission's conservation objectives and promote conservation by efficient recourse use, and by reducing and/or shifting system load.

D. The project should help to develop new resources and/or processes and to advance supply technology.

E. The project should help to improve operating efficiency.

F. Utility's priority setting process should minimize expense on those concepts which have a low probability of success.

4. Other Energy Production and System Efficiency Activities

PG&E's proposed budget for 1982 includes $21,427,000 for various biomass projects including various landfill gas projects, synthetic natural gas from manure, and digester gas projects. The bulk of this budget is for capital expenditures.

As part of a five-year program PG&E proposes to spend $15,881,000 to convert primary feeders from 12 KV to 21 KV to reduce distribution losses. PG&E also has budgeted $9,095,000 for conversion of incandescent and mercury vapor streetlights to high pressure sodium vapor lights. We concur with these programs.

B. Miscellaneous

1. PURPA

TURN presented witness R. Spertus to testify on whether the Commission is bound by the advertising standards set forth in Title I, Section 113(b) (5) and Section 115(h) of PURPA; whether PG&E has violated such standards by its placing of political printed matters in its customer bill or dividend envelopes; and, if affirmative, what lawful remedies should be ordered by the Commission.

Witness Spertus alleges that PG&E has violated the following sections of PURPA by placing certain printed matter into the customer bill or shareholders dividend envelopes:

> "Title I, section 113(b)(5)
>
> "Advertising -- No electric utility may recover from any person other than the shoreholder (or other owners) of such utility any direct or indirect expenditure by such utility for promotional or political advertising as defined in section 115(h).
>
> "Title I, section 115(h) (selections):
>
> "(A) The term 'advertising' means the commercial use, by an electric utility, of any media, including newspaper, printed matter, radio, and television in order to transmit a message to a substantial number of members of the public or to such utility's electric consumers.
>
> "(B) The term 'political advertising' means any advertising for the purposes of influencing public opinion with respect to legislative, administrative, or with respect to any controversial issue of public importance." (Emphasis added.)

Spertus states that the cost of distributing these messages would be considerably higher to PG&E if it did not pick up a free ride by using the bill and dividend envelopes. He further testified by including the PG&E Progress in such mailing, it deprives sale and usage of such space to other advertisers. The political advertising themes that Spertus refers to are the need for prompt licensing of Diablo, the need to take Canadian gas, the need for improvement in PG&E's regulatory treatment in order to ensure future electric supplies. He recommends that the Commission disallow PG&E the mailing costs for its customers monthly bills and shareholders dividends because they are direct or indirect expenditures for political advertising and further to institute a mechanism for physical production of bill inserts and for the writing and editing of the information contained in them.

PG&E argues that TURN's witness is in error in that this Commission did not adopt the PURPA advertising standards. PG&E states that the Commission, in considering whether it should adopt the PURPA standards, reported to the Department of Energy (DOE) that by Public Utilities (PU) Code Section 796 and adoption of the use of FPC Account 426.4 of the Uniform System of Accounts for Public Utilities and Licenses, it complies with the PURPA standard on advertising. PG&E argues that the California code provisions, unlike PURPA, do not include, as political advertising, the discussion of controversial issues of public importance. PG&E further argues that even if the Commission had adopted PURPA definitions of political advertising, there would be no violation since PG&E's stockholders pay for the cost of the PG&E Progress and shareholders letters, and there is no prohibition against use of billing or dividend envelopes to distribute such material. PG&E further argues that virtually every example of alleged political advertising in the PG&E Progress fits within one of the exceptions in PURPA, Section 115(h)(2) and that the remedies proposed by Spertus were unsupported and in some cases unconstitutional.

We are persuaded that TURN's arguments have solid conceptual merit. However, for the reasons which follow, we decline to implement at this time the access mechanisms which TURN proposes. We also shall not bar PG&E from continuing to mail out the Progress in the billing and dividend envelopes. We do not rule out the possibility of such action in the future, however,

Our analysis begins with the question of whether this Commission adopted a PURPA standard barring the utility from recouping from ratepayers costs associated with political advertising. In its November 8, 1980 PURPA compliance filing with the Department of Energy, the Commission addressed the question, "Does the Advertising Standard that you had adopted require ... [d]efinitions of political and promotional advertising which conform with those given in section 115(h)(1) and (2) or 304(b)(1) and (2) of PURPA?" The Commission's answer was "Yes." We feel it is clear that this Commission has adopted the prohibition on the recoupment by utilities of political advertising expenditures from ratepayers.

We next must ask whether PG&E engages in political advertising in the Progress. It is clear that, from time to time, PG&E does engage in such advertising. We need only look at the July, 1981, Progress which TURN appended to its brief. The editorial there contained a lengthy critique of the so-called "off gas" requirement mandated by Congress in the 1978 Powerplant and Industrial Fuel Use Act (PIFUA). The editorial was obviously comment "for the purpose of influencing public opinion with respect to legislative ... or ... controversial issues of public importance," since it came at a time when Congress was considering amendments to PIFUA in conjunction with tax and budget matters. (We note Congress did in fact vote to terminate the off gas requirement for utilities.) We have to state, candidly, that we think PG&E's position on this issue was correct. The editorial even contained remarks of the Commission's President pointing out the expense associated with the off gas requirement. But our agreement with PG&E on such an issue does not blind us to the fact that, from time to time, the Progress contains political comment on important and controversial issues of public policy. If we are to adhere to the standards which Congress has set out for us in PURPA, we must recognize political speech for what it is and act to ensure that ratepayers do not help the utility, directly or indirectly, meet the costs of mailing or distributing such speech.

It is frequently stated by PG&E that the ratepayers face no extra cost because of the Progress. It is stated that shareholders pay for the entire cost of composing and printing the Progress. We acknowledge this is true. PG&E claims it merely inserts the Progress into the unused "extra" space in the billing or dividend envelope and does not cause any extra postage costs. (Postage is paid for, as is the case with envelopes, by ratepayers.) We acknowledge that no extra envelope or postage costs are incurred. The fallacy in PG&E's position, however, is its implicit claim that there is no other use to which the "extra" space may be put.*/ We think there are or may be many other uses for the "extra" space. That such space could be sold to public advertisers (without any extra postage cost) at once demonstrates that the space surely has economic value.**/ That economic "value" belongs to the ratepayers, who create the space by paying for the envelope and postage. Use of the space for the Progress instead of some other purposes deprives the ratepayers of that "value," which they own. Since PG&E captures that "value" without charge, it is recovering a cost from the ratepayers. We believe such recovery is forbidden under PURPA.

We shall explain further our view that there are other uses to which the "extra" space may be put, in order to show that there definitely is a cost which ratepayers are forced to bear when the Progress is mailed with the customer bill. TURN introduced into the record remarks made by PG&E's Manager of Energy Conservation and Services at the Commonwealth Club on April 27, 1981:

> "When it comes to marketing communications the seemingly unexciting medium of our bill offers a surprising amount of pull. Take the case of our furnace filter promotion. We had planned to run a bill insert promoting a 50 cents off coupon for furnace filter replacements. However, the CPUC preempted the bill insert with a legal notice and we had to resort to newspaper advertising to promote the certificate. Spending about $150,000 we managed to get 29,000 redeemed. Six months later when time came to change the filters

---

* We define such "extra" space as the space remaining in the billing or dividend envelope, after inclusion of the monthly bill, dividend check and/or required legal notices, for inclusion of other materials up to such total envelope weight as will not result in any additional postage cost. The "extra" space is the space which the Progress now occupies.

** TURN alleges the "extra" space in Kansas Gas and Electric billing envelopes is now being sold, without objection by the public, to commercial advertisers as a means of raising revenue to offset the utility's revenue requirement.

> again we ran the bill insert for $7,000 and got 23,000 coupons redeemed. So obviously the bill insert is the way to go."

These remarks illustrate perfectly the "opportunity cost" that the _Progress_ causes ratepayers to bear. PG&E's management obviously chose to mail the _Progress_ and the legal notice, rather than the legal notice and the useful furnace filter replacement promotion. As a result, ratepayers were forced to bear the costs of inefficient use of the billing envelope. Use of the "extra" space for the _Progress_ deprived ratepayers of all the savings inherent in conservation, i.e., in the utility's selling less gas due to more efficient furnace operation.

PG&E would at the very least have to pay fourth class bulk mail rates for the Progress if it did not mail it with the customer bill. It is this cost which PG&E improperly recovers, albeit indirectly, from ratepayers, who are deprived of the value which their expenditures (for postage and envelopes) have created. It is not content that we are concerned with. The significant point to remember is that we have no way of knowing how many times in the past PG&E was (or how many times in the future it would be) forced, due to inclusion of the _Progress_, to defer a more efficient use of the "extra" space in the billing envelope which would have saved (or earned) money for ratepayers.

The same analysis, however, cannot be applied to PG&E's practice of mailing the _Progress_ in dividend envelopes. Although it might be said that ratepayers technically "own" the "extra" space in the dividend envelope, it cannot be said that _economic_ (as opposed to political or propagandistic) "value" is being lost to ratepayers as a result of inclusion of the Progress in that space. While it is certainly conceivable that the "extra" space in the billing envelope could be sold to would be advertisers, we are not aware of corporations selling space in their dividend envelopes to would be advertisers. By contrast, the normal and customary practice is for corporate management to communicate with shareholders when dividends are distributed. This inures to ratepayers' benefit, at least in part, because it allows for capital to be raised privately, without ratepayers having to put capital up front for utility operations. We cannot see any real "opportunity cost" associated with mailing the Progress in the dividend envelopes.

Having come this far in our analysis, we next must ask what steps we should take to bar PG&E from recovering from ratepayers a cost of its political advertising or, alternatively stated, what steps we should take to utilize most efficiently for the ratepayers' benefit the "extra" space occupied by the Progress in the billing envelope. We see a number of possibilities and a host of problems for each possibility.

One possible solution is to ban the Progress entirely. We are inclined to believe that such action is constitutionally permissible as a proper "time, place and manner" restriction on speech that would be allowed under Consolidated Edison Co. v. Public Service Commission (1980) 447 U.S. 530. There the high court stated the well established principle that the government may impose time, place and manner restrictions on the exercise of speech where such restrictions "serve a significant governmental interest and leave ample alternative channels for communication. [Citations.]" (Id. at p. 535.) The significant governmental interest to be served by an across the board ban on the Progress in billing envelopes is the interest identified by Congress in PURPA, namely, saving ratepayers from having to bear the cost, directly or indirectly, of utility political advertising. As demonstrated above, that cost is real and, although as yet unquantified, potentially enormous, whether viewed as the "opportunity cost" of foregone revenue or otherwise. We also believe there are ample alternative means by which PG&E may broadcast or distribute its views to the public.

But we have to ask if such a ban would ultimately be in the ratepayers' best interest. As it is now, PG&E's Progress does contain from time to time useful information about conservation programs, cost saving measures, Commission action and the like. The cost of composing and printing such information is borne by shareholders. Such benefit to ratepayers must be weighed against the "opportunity cost" borne by ratepayers. It is unclear at present how that balance should be struck.

Even more importantly, it is incumbent on TURN to demonstrate whether it is permissible to ban the Progress entirely if we simply intend to use that "extra" space for conservation messages, or other speech, composed by the Commission, interested public participants such as TURN or other parties. This might simply be a substitution of one form of speech for another, a preference for governmentally sponsored or governmentally allowed speech. Such a preference could be more dangerous than the evil which TURN seeks to correct. We believe it might be invalidated for the reasons the content-based regulation (a ban on pro-nuclear speech) was invalidated in Consolidated Edison. This is a problem to which parties like TURN must devote greater attention if we are to arrive at a permissible means of more efficiently using the "extra" space in billing envelopes.

A second possibility is to employ a public access mechanism similar to what TURN proposes. In other words, for every political message PG&E propagates in the Progress, we would allow TURN or other consumer groups to reply. We realize such opportunities to reply are already provided by private media. But we are concerned that we may lack the expertise, staff resources and/or public mandate to devote ourselves to the task of identifying what is or is not political speech in any given instance. We also are concerned that we do not have in place a fair mechanism for determining just who should be allowed to respond to PG&E. Should it be TURN? California Manufacturers Association? California Retailers Association? Citizens Action League? Perhaps we should allow for a lottery to determine such opportunity to respond. However, we think this would simply result in chaos and confusion. Again, we think this is a problem to which TURN has given insufficient attention. TURN itself recognizes the difficulties inherent in an access mechanism.

A third possibility is to charge PG&E a fee for use of the "extra" space whenever it indulges in political speech. Again we see problems in identifying what is or is not political speech. We think it possible that innumerable hours of hearing time would be devoted to identifying what fee should be charged. Given our many other tasks, we do not think that would be productive.

A fourth possibility is to auction the extra space off to the highest reputable commercial advertiser. We invite TURN to report to us more fully on the experiment underway at Kansas Gas and Electric. In this era of high utility bills, we think every means of meeting the revenue requirement without increasing customers' bills must be explored. Such advertising would be similar to the Yellow Pages space sold by telephone utilities, except that the space available would only be the "extra" space as defined above. We think it possible that a significant amount of money could be raised by this means. We also think it possible that devoting the "extra" space to commercial speech solely for purposes of revenue generation to offset the revenue requirement would avoid the difficult First Amendment problems associated with the first three possibilities discussed above.

There may be other possibilities. We invite TURN or any other interested party to file an application with this Commission with a proposed solution to the "extra" space problem. The application would seek an order from us to the utilities, such as PG&E, that they utilize the economic value of the "extra space" more efficiently for ratepayers' benefit. We caution, however, that we will not lightly adopt such an order and that the considerable First Amendment problems must be fully addressed in such application.

2. Equal Employment
<u>Opportunity (EEO) Litigation</u>

The staff accountant recommended that expenditures relating to pending EEO litigation should be disallowed from test year estimates. In 1980, PG&E expended $107,597 on such EEO matters. We shall grant the staff's recommendation since it is not Commission policy to charge the ratepayer expenditures not incurred for their benefit. Obviously, this issue cannot be conclusively resolved at this time due to the pending status of this litigation.

The question of disallowance of EEO litigation expenses was first addressed by this Commission in D. 88232 (1977) 83 CPUC 149, 213. At that time the expenses at issue were related to settlement of a 1973 consent decree between the Bell System (Pacific Telephone being a party respondent) and the Equal Employment Opportunity Commission (EEOC). This Commission ordered the disallowance of such penalty payments only, making the unequivocal statement that such disallowance "does not include amounts connected with litigation of EEOC problems, administration of EEOC programs or compliance with the consent decree." However, the basis for the Commission disallowance, the U.S. Supreme Court decision in <u>NAACP v. FPC</u>, 48 L.Ed2d 248, 292 (1976) specified that disallowance of other similar costs, such as, attorney's fees that can or have been demonstrably quantified by judicial decree or the final action of a duly charged administrative agency, shall be disallowed as illegal, unnecessary or duplicative.

In 1980, a similar recommendation to disallow salaries and legal fees incurred in defending the Thompson case, an affirmative action class-action suit, was addressed in D. 92549. At the time of this recommendation, Southern California Edison had offered to settle the case with no indication of an acceptance by the plaintiffs. The Commission granted the disallowance assuming that such an offer was not made for the sole aim of avoiding costs of litigation and that some settlement would be reached, citing similar treatment by the Federal Energy Regulatory Commission in its Accounting Release No. AR-12. This release states that utility expenditures resulting from employment practices which are found to be discriminatory by judicial or administrative decree or which are the result of a consent decree will be classified as non-operating expenses.

In the instant rate proceeding, the Commission is asked to go one step beyond the established precedents of disallowing incurred EEO settlement and litigation costs by excluding identifiable EEO litigation expenses prior to a final disposition of such litigation. A resolution of this request can be found in the principles underlying the prior Commission orders in D. 88232 and D. 92549. It is a well established principle of ratemaking that rates charged by utilities shall be reasonable and only include expenditures that are incurred for the benefit of the ratepayer. Excluded from rates are particular expenses that represent inefficiency, abuse of managerial discretion, actions inimical to the public interest and economic waste. (Public Utilities Code §§451, 728.) The propriety of the expenses at issue here cannot be determined until a final disposition of the relevant litigation. If such litigation is resolved at the time of the next rate case filing, only such allowable expenses as defined in D.88232 and D. 92549 shall be accepted. We, also, take official notice that the Commission is presently investigating EEO and procurement practices in C. 10308, in which PG&E is a respondent. Future rate case filings must also be guided by any relevant final order in this pending investigation.

X. Rate Design

A. Marginal Cost, Revenue Allocation, and Rate Design - Electric Department

1. Introduction

This portion of the proceeding deals with a determination of which customers, or groups of customers will pay what portion of the revenue requirement. We will first summarize the positions of the parties, then discuss marginal costs, and determine a marginal cost methodology. We will then proceed to the allocation of the revenue requirement to the various customer classes. The final portion of our discussion will be concerned with specific rate design proposals.

Position of the Parties

Before examining rate design and revenue allocation, we need a brief summary of the position of the various parties in this proceeding. In our later discussion we will refer in more detail to the arguments that were most helpful in framing the issues. This opinion may not contain a detailed discussion of the position and argument of every party.

The parties can be divided into three groups: (1) those proposing rates based on marginal costs, (2) those rejecting the use of marginal costs and relying on fully allocated embedded costs, and (3) those with specific proposals not involving general methodologies. These groups are shown below:

Group 1 - PG&E, Staff, TURN, Farm Bureau, Energy Commission, Natural Resources Defense Council, Inc. (NRDC), and California Retailers Association (CRA).

Group 2 - California Manufacturers Association (CMA), Stanford, Industrial Users, GSA, and United States Steel Corporation (U.S. Steel).

Group 3 - Western Mobilehome Association and the City of Oakland.

a. PG&E

PG&E provided a complete marginal cost method which it characterizes as the "next generation" of marginal cost methodology. It is designed to be used by both system resource planners and rate designers.

PG&E allowed the revenue requirement using the "equal percentage of the difference" (EPD) method based upon marginal energy, marginal generation, and marginal transmission costs. This allocation is consistent with the Commission-adopted allocation in PG&E's last general rate case.

Specific rate design changes proposed by PG&E are:

1. Eliminate residential customer charge.
2. Offer a new limited experimental TOU schedule for residential customers.
3. Consolidate certain industrial and commercial schedules.
4. Retain most and selectively increase certain industrial and commercial demand charges.

b. Staff

The Commission staff presented a marginal cost study intended strictly for ratemaking purposes. It differs greatly from PG&E in theory but only slightly in practice. The allocation of the revenue burden recommended by staff is based on short-run marginal cost (SRMC) which is essentially marginal energy cost only. Rates based on these costs are scaled back to the revenue requirement using the EPD method used by PG&E.

Staff proposes that the residential customer charge be retained and that no new or increased customer or demand charges be adopted for industrial and commercial customer classes.

c. TURN

TURN supports rates based on marginal costs; however, it has certain philosophical differences with PG&E. TURN proposes that all customer classes, rather than just the residential class, share the burden of lifeline rates. In addition, TURN proposes to allocate rates based on a class marginal rate concept.

Regarding rate design, TURN supports elimination of the residential customer charge, but applying a minimum bill for zero usage vacation homes which contribute no revenue. TURN also supports continuation of the three-tier, 38% differential residential rate structure.

d. Farm Bureau

Farm Bureau accepts the use of marginal costs for allocation and rate design but differs with both staff and PG&E regarding methodology. Although it accepts marginal costing, Farm Bureau believes there is also merit in the fully allocated embedded cost approach. Under either approach the agricultural class should receive an increase less than the average system increase.

Regarding rate design, Farm Bureau supports the staff position of retaining the residential customer charge and either demand or customer charges for the agricultural class. The Farm Bureau also advocates reducing the steepness of the inversion of the three-tier residential rates.

e. Energy Commission

The Energy Commission strongly supports the use of marginal costs as the keystone of rate design. The heart of the Energy Commission's recommendation is that customer charges should be eliminated and demand charges should be eliminated or sharply reduced. This would result in the collection of a greater portion of the revenue requirement through energy charges which should promote conservation.

f. NRDC

The sole concern of the NRDC in this proceeding was the use of marginal costs in pricing electricity. The NRDC sees significant flaws in the PG&E proposed method and recommends that it be rejected for any use other than setting consumer rates.

g. CRA

CRA was concerned not with the methodology of computing marginal costs, but with the use of marginal costs to allocate the revenue requirement. CRA contends that because PG&E's system is not optimum, there are no marginal generation costs. Also, CRA supports inclusion of marginal distribution and customer costs as well as marginal energy and transmission costs in allocating revenues. As a result the residential class would receive a percentage increase significantly higher than any other class.

h. CMA

CMA supports the concept of allocated embedded cost particularly for revenue allocation. It sees the proper use of marginal costs to be to design rates within each customer class. However, it argues that if some marginal costs are used, then all such costs (marginal energy, demand, and customer) should be used in revenue allocation. CMA's most ardent argument was against TURN's concept of customer class marginal rate.

i. Industrial Users

The Industrial Users, like CMA, firmly believe in embedded rather than marginal costs. The Industrial Users pointed out distortions resulting whenever some of the costs are not included.

The Industrial Users also argue that the proposed PG&E rates place too heavy a burden on the large light and power class, compared with the rates for the same type of customers in neighboring states. They propose that the Commission consider strongly the economic impact of the proposed rates on their members.

j. U.S. Steel

The position of U.S. Steel and other steel producers is virtually identical to that of the CMA and the Industrial Users.

k. GSA

The GSA presented testimony supporting the use of embedded costs. Within the embedded cost theory, it argues that relative class rates of return should be held within 50% of the overall allowed rate of return. It also proposes that in five years the rate of return for each class should be equal.

l. Stanford

Stanford argues for the embedded cost theory and equalized class rates of return. Stanford feels that the proposed rates place disproportionate burdens on the large power and light customers.

Stanford opposes the staff's position of freezing demand and customer charges. Also, Stanford would like the Commission to reopen OII 56 to reconsider ECAC issues and to open an investigation of TOU rates.

m. Western Mobilehome Association

The Western Mobilehome Association has the limited concern in this proceeding of maintaining a proper discount for master meter customers. Such customers now receive a 26% discount. The Western Mobilehome Association proposes that this discount be increased to 34% if the residential customer charge is eliminated, or that the 26% discount be reduced to 23% if the present customer charge is retained.

n. City of Oakland

The City of Oakland presented arguments regarding the streetlighting schedules. It supports an equal percentage increase to be applied to the various streetlighting schedules rather than an equal cents per kWh as proposed by PG&E.

2. Marginal Costs in General

The central issue is whether we will adopt marginal costs or fully allocated embedded costs as the basis of rate design.

PG&E simply recognizes no basis other than marginal costs for ratesetting. Although it prepared an embedded cost of service study, its purpose was simply to arrive at the proper jurisdictional allocations. PG&E evidently considers the issue so well-settled that it did not even respond to the arguments of those who favor embedded costs.

The parties in favor of embedded costs present no new arguments. The arguments were last made, discussed, and decided in D.92549 (SoCal Edison's general rate case). The basic position in favor of marginal costs is stated by the staff in Exhibit 37 as follows:

> "Another way to understand the fundamental or essential need to use marginal costs is by observing that rates which promote the most conservation, efficiency, and equity must ultimately be based on marginal costs. The result of basing rates on marginal costs is that the rate equals the cost of producing one more unit, or the savings from producing one less unit. In this way each consumer pays the resource cost (additional cost of the added quantity) for additional consumption, or saves the resource cost when consumption is reduced. Conservation is achieved since consumption is made only when the benefits of consumption are greater than or equal to the cost (i.e., there is no 'wasteful' use). Efficiency is achieved since the least cost combination of resources neither over-uses the good (which would occur if its price is below marginal cost) nor underuses the good (which would occur if the price is over the marginal cost). Finally, equity is achieved since no customer underpays or overpays relative to the resource cost (e.g., consumers choosing solar or insulation are not treated inequitably since they save the resource cost from their lack of consumption and the non-solar or noninsulation electric consumers pay the resource cost for their choice to consume)."

Those favoring embedded cost assume that every aspect of cost incurred by the utility should be matched by a corresponding revenue recovery. Also, each class should not only pay its embedded expenses, but also make an equal contribution to the overall rate of return. Embedded cost advocates usually argue against marginal cost pricing by showing that prices set at marginal costs produce revenue far in excess of the revenue requirement and that attempts to scale back revenues are arbitrary and result in major distortions of the revenue burden between customer classes. As a result, one customer class subsidizes others.

These arguments fail for several reasons. Rate design has many goals, among which economic efficiency is certainly prominent; but equally important is the goal of conservation. A utility has many input costs in the production of energy. Marginal cost pricing allows us to signal consumers those input elements which we consider most important for conservation.

Costs need not be recovered in exactly the same pattern in which they were incurred. That is, we are not bound by a pure embedded cost of service pricing model. We find that the pricing of electricity based upon the cost of the last unit produced is equitable and allows more flexibility in encouraging conservation of energy. We therefore will continue our strong reliance on marginal cost pricing.

3. <u>Marginal Cost Methodology</u>

Having decided marginal costs will continue as the basis for setting rates, we can now discuss the proper method for computing marginal costs.

Marginal cost is the change in total cost resulting from a change in output. It may also be understood as the cost to produce an additional unit of a commodity, or the savings from producing one unit less. The total marginal cost of an electric utility includes energy costs, demand or capacity costs, and customer costs. It will be helpful to keep in mind the elements of marginal costs in our further discussion:

I. Marginal Energy Costs.

II. Marginal Demand or Marginal Capacity Costs.

a. Generation

b. Transmission

c. Primary distribution

d. Secondary distribution

III. Marginal Customer Costs

Marginal energy costs are the per kWh cost of fuel, operation, and maintenance. Marginal demand or capacity costs are the kW costs of additional generation, transmission, and distribution investments which are related to demand plus demand-related expenses. Marginal customer costs are the costs of adding an additional customer to the system.

Of these three elements the greatest controversy surrounds demand generation costs and marginal energy costs. Marginal customer costs were of less interest and will be dealt with when we discuss our allocation procedures.

The controversy surrounding demand generation costs involves the proper methodology for computing them. Some of the reasons for this controversy can be seen when we look at the use to which these marginal costs calculations are put. Marginal costs are used for resource planning, that is, investment decisions to be made in the future, cogeneration pricing, small power production pricing, cost effectiveness of conservation planning, and ratesetting.

Should there be one and only one general method for computing marginal costs which are, in turn, used for various purposes? We think so. However, within the one general theory there can be different calculations of marginal costs depending on the purposes they serve and the time period which is being considered as follows:

I. Prices that the utility must pay for inputs (cogeneration, small power production, conservation, et al.) and;

II. Prices that the utility must charge its customers for electric consumption (ratesetting).

and

I. Short-run time period.

II. Long-run time period.

With short-run marginal costs a firm cannot change its fixed capital goods or capacity to respond to a change in demand; but it can change its variable inputs. In the long-run, a firm can vary both its fixed assets and its variable inputs.

It appears that the time factor problems (long-run versus short-run) and the purposes to which marginal costs will be applied, constitute the major reason for the controversy over marginal costs in this proceeding. Many parties apparently believe that the overall general methodology must be considered and decided in this case in order for us to use marginal costs as a basis for ratesetting.

They believe that this decision will be applicable to all purposes for which marginal costs are used. This is a major error. This proceeding is a general rate case. We have established as our policy that marginal costs will be the keystone for setting rates. We are required in this proceeding to deal with marginal cost concepts only for ratesetting purposes. Discussion concerning other uses of marginal cost analysis belongs in other proceedings. (OIR 2, for Cogeneration, and Small Power Production Pricing for example.)

In this proceeding there was little controversy surrounding the computation of the demand costs related to transmission or the computation of the marginal customer costs. PG&E's computations will be accepted.

The staff pointed out that there are three principal means of calculating total marginal costs: (1) short-run energy plus short-run capacity, (2) short-run energy plus long-run capacity, and (3) long-run energy plus long-run capacity. The staff characterizes PG&E's approach to marginal costs methodology as the first, short-run energy plus short-run capacity, but believes the second approach short-run energy plus long-run capacity costs is correct. We believe that PG&E's choice is actually the second also. However, there are major differences between PG&E and the staff on the calculation of the long-run capacity costs.

Disagreements regarding the computation of long-run marginal capacity costs need not be resolved in this proceeding because we believe short-run energy plus short-run capacity costs should be used in setting rates; we want to show the consumer the present cost of his consumption. We need not concern ourselves in this proceeding with computation of long-run capacity costs.

We believe that this entire discussion shows that one general method can accept different marginal costs calculations when temporal or other distinctions are considered.

Once we have decided that for ratesetting purposes we are interested primarily in short-run energy plus short-run capacity, many of the issues are either eliminated or greatly simplified and there appears to be a stronger consensus among several of the parties in this proceeding concerning marginal cost calculations.

At this point, it is most useful to turn to the basic marginal cost equation offered by PG&E:

MC = shortage cost + operating cost, + the investment term.

Most parties agreed with this concept of marginal costs; the controversies involved the investment term. As discussed previously, we are concerned with a short-run time period in which the fixed assets or capital goods of a firm cannot change in response to a change in demand. Therefore, the equation that we adopt eliminates the investment term: MC = shortage cost - operating costs.

We will now discuss the two remaining terms of our marginal costs equation. The first term, the shortage costs, can best be described by an illustration. Assume that a reasonable reserve capacity for PG&E is 15%, and an equilibrium situation exists. In other words, PG&E is producing a certain amount of output at a certain price and maintains a reserve capacity of 15%. The next step is to assume a small increase in demand. Let us assume then that PG&E produces this increased load in the short term where no new capital additions are possible. The effect will be a decrease in the reserve margin. Let's assume it goes from 15% to 12%. The shortage costs can be viewed as the cost of increasing the reserve margin from 12% back to 15%. This shortage cost can be viewed and calculated in several ways. (1) One could look at the shortage cost as the cost of purchasing energy from outside sources at the time of system stress to increase the reserve margin. (2) The shortage costs could be determined by increasing the price charged to customers so that the demand would be decreased and the reserve margin brought back to the required level. This is referred to as the market clearing price. (3) The cost of load management incentive to reduce demand could be calculated. These examples would be so-called direct calculations of the shortage costs.

The shortage costs could also be calculated indirectly. PG&E has done so by creating a proxy to measure the shortage costs. PG&E attempts to measure what a customer would have to pay to avoid a shortage by assuming that the least cost to customers would be the lease capital-intensive addition to capacity to avoid a shortage. PG&E projects this least cost capital addition to be a gas turbine. Several parties to this proceeding seem to have difficulty with this concept because there is no gas turbine in PG&E's resource plan.

The Farm Bureau brief states:

> "That the PG and E approach is intuitively wrong was illustrated by a series of questions asked by Farm Bureau's counsel of PG and E's marginal cost witness. A doubling or tripling of the capital cost of a coal plant, a combined cycle plant or a geothermal plant (or similarly large reductions in cost) would have no effect on PG and E's estimate of marginal generation costs (Tr. 5157). However a change in the cost of a gas turbine would significantly impact PG and E's calculated marginal cost. In other words, a change in the capital cost of a resource not in the resource plan changes marginal cost; a change in the capital cost of resource in the plan has no effect. The methodology approved in O.I.I. No. 67 would respond to appropriate capital cost changes; no doubt, this is one reason the Commission adopted it. The PG and E presentation in this case would not and should be rejected."

What seems to be the heart of the confusion is that the gas turbine is but a proxy for the calculation of shortage costs and does not necessarily have to be in the resource plan of PG&E. And, in fact, with our short-term consideration of marginal costs, the resource plan of PG&E becomes irrelevant. PG&E's concept is that its proxy for the shortage costs (gas turbine) is the most that the customer would ever have to pay to avoid a shortage. Therefore, the calculation of the costs of the addition of a gas turbine becomes a maximum calculation of the shortage costs.

Another way to estimate the shortage cost is presented by the staff. This approach is to proxy the shortage cost by calculating the average cost of all planned resource additions in PG&E's resource plan. Staff points out that system planners are always estimating the shortage cost and planning resources accordingly: resource plans intend to neither underbuild plant nor overbuild. It notes that resource plans are intended to meet demand without overbuilding. Staff estimates the test year present value average of the resource plan to cost $116.57/KW/Year.

Other parties, namely, TURN, CMA, and NRDC, criticize the use of the gas turbine as a proxy because they feel that a more direct calculation of the shortage costs could and should be made. We agree. TURN's witness Wells outlined a method using demand elasticities to compute a shortage cost. CMA advocates that a proper measure of shortage costs would be the price of purchased power at times of system stress. Although these other methods were suggested, no calculations were presented. We therefore will accept the calculation using the gas turbine as a proxy.

PG&E, in its brief, has conceded the need for further study of a direct calculation of the shortage costs as suggested by the parties. We request that PG&E conduct such studies and to provide the results or at least the status of the results in its next reasonableness review ECAC proceeding. In addition, the subjects of the additional studies requested by the staff are of great interest to us.

The second term of our adopted marginal cost equation concerns operating expense. The parties all agreed that the term would be represented by the marginal energy cost plus variable operational and maintenance expenses. There was, however, controversy surrounding calculation of this term, which we will deal with below.

4. Marginal Cost Calculation

Only the staff and PG&E presented complete marginal cost studies in this proceeding. Other parties offered comments on the calculation of various elements of the total calculation.

Table X-1 below shows the calculations of annual marginal costs by voltage level by the staff and PG&E.

Table X-1

Pacific Gas and Electric Company
Electric Department

SUMMARY OF ANNUAL MARGINAL COSTS
BY VOLTAGE LEVEL

(1982 Dollars)

Line No.	Voltage Level	Annual Marginal Costs	
		Staff	PG&E
	Transmission		
1	Demand ($/kW/year)	$107.88	$ 84.00
2	Generation	91.92	68.04
3	Transmission	15.96	15.96
4	Energy (¢/kWh)	10.11	8.01
5	Customer ($/customer/year)	944.00	944.00
	Primary Distribution		
6	Demand ($/kW/year)	154.44	128.40
7	Generation	94.56	69.96
8	Transmission	16.44	16.44
9	Primary Distribution	43.44	42.00
10	Energy (¢/kWh)	10.29	8.15
11	Customer ($/customer/year	369.00	369.00
	Secondary Distribution		
12	Demand ($/kW/year)	211.68	182.04
13	Generation	96.84	71.64
14	Transmission	16.80	16.80
15	Primary Distribution	44.52	43.08
16	Secondary Distribution	53.52	50.52
17	Energy (¢/kWh)	10.44	8.27
18	Customer ($/customer/year)	182.00	182.00

The differences between the staff and PG&E are set forth on page 2-5 and 2-6 of Exhibit 37, as shown below:

"12. The differences in results between PG&E and staff occur for several reasons. First, the marginal generation demand cost is based on a 24 year depreciable life for a gas turbine rather than the 30 years used by PG&E. The staff marginal generation demand cost also includes a working cash adjustment. Second, the marginal distribution demand cost is calculated by a regression of data over 13 years rather than using PG&E's average over 15 years. Finally, the marginal energy costs are calculated (1) using 1982 PG&E resources without Diablo Canyon units 1 or 2, (2) based on oil costs escalating at 25% per year in 1981 and 1982 as opposed to PG&E's use of 16% per year (residual), 15.5% per year distillate, and (3) weighted by kilowatt-hours (load) rather than hours to aggregate hourly energy costs to costing period energy costs."

The differences became the relevant issues in calculating the marginal costs. As can be seen from Table X-1, PG&E and the staff agree on the calculation of the marginal customer costs and demand-related transmission costs. These calculations will be adopted.

Marginal Demand Cost

Generation

To compute the marginal demand cost we must first determine the useful life of the gas turbine unit. The staff proposes a 24-year useful life, consistent with PG&E's depreciation schedules in its Results of Operations. PG&E concurs, and the 24-year useful life will be adopted.

The remaining differences are the annual carrying charge and cash working capital. PG&E provided testimony that the gas turbine it was using as an example required no fuel inventory. (Baldwin Tr. 4888-89). We will therefore adopt PG&E's carrying cost of 9.1% and PG&E's estimate of cash working capital.

Distribution

The issue regarding Demand Distribution cost is whether averaging or regression analysis should be used. The staff argued for regression analysis as being consistent with D.92749. However, PG&E attempted the regression analysis but obtained "unreasonable results". Therefore, we will adopt the averaging technique for this proceeding. The difference between the two techniques is rather insignificant (3%).

Marginal Energy Cost

The determination of the marginal energy cost was the greatest area of controversy in the calculation of marginal costs. The arguments concerned two issues:

1. Inclusion of Diablo in determining marginal energy costs, and
2. The projected future price of fuel oil.

When it filed its brief in this proceeding, PG&E had just been granted permission from the Nuclear Regulatory Commission (NRC) for low power testing. PG&E argued that its operational projected dates for Diablo units were very reasonable in light of its licensing progress.

The staff, on the other hand, argued that since PG&E has experienced delays in the past, it would probably also have delays in the future. Also, the staff felt that we should reexamine PG&E's marginal cost when Diablo becomes operational. Although the staff's arguments appear to be weak regarding the issue, events which occurred after the submission of this case support the staff position. Even if the "mirror image blueprint problem" had not come to light, it is doubtful if Diablo could be sufficiently operational during 1981-1982 to affect its marginal energy costs for this case. We adopt the staff's position of not including Diablo in the calculation of marginal energy costs.

The remaining issue concerns the proper projections of fuel oil in 1981 and 1982. PG&E uses an escalation rate of 16% per year in 1981 and 1982 for residual oil, and 15.5% per year for distillate oil. The staff uses 25% per year for all oil input costs.

The staff argument is concisely set forth on pages 115 and 116 of its brief as follows:

> "Staff use of 25% annual escalation rate is based on two factors. First, PG&E's fuel oil cost has increased 24% per year from 1973 to 1979. The annual increase was 28% from 1973 to 1980. FPC Form 1 records over 1973-79 confirm an increase of 24-25% in the average cost of fuel burned at Pittsburg, Potrero, Hunters Point and Moss Landing power plants. Staff believes actual experience of 24-28% will continue until 1982.
>
> "Second, the world market price for crude oil has escalated at an annually compounded rate of 48% per year from 1973 to 1980 ($3 per barrel in 1973 to $32 per barrel in 1980). The cost of crude oil from Saudi Arabia has escalated at a rate of 27% per year from 1977-81. The average cost of imported crude oil has escalated 25% per year from 1977-81. Number 6 and number 2 fuel oil prices used as part of an alternate fuel pricing study to set natural gas rates shows these fuels escalating per year between 1977-80 at 26% and 31%, respectively."

* * *

"Staff generally believes the experience of 48% per year from 1973-80 is more likely to occur than a lesser impact, but is using 25% per year because of the possible offsetting effects of new domestic oil, recession, conservation and price effects. The use of 25% per year is in line with the 25-31% annual escalations from 1977-81."

Several other witnesses contested the staff's projections. CRA witness King finds that both PG&E and the staff have significantly overestimated the price of fuel oil. He projected an increase of about 7% in 1981 and no increase in 1982. The Farm Bureau also argues that both PG&E and the staff have overestimated fuel prices.

Cicchetti, a rebuttal witness sponsored by PG&E concludes that PG&E's estimate is more reasonable than the staff's, considering numerous other factors as shown in Exhibit 138 on pages 25-26 as follows:

"In forecasting 1982 fuel oil prices, one should also consider some factors that witness Mattson ignores: (1) there is an oil glut; (2) the dollar is increasing in strength as our oil dependence has been reduced, therefore, despite the glut of oil, the real income of OPEC is increasing even though they have recently decided to increase crude prices only slightly; (3) oil prices were decontrolled in early 1981 and will not affect the 1982 growth rate; (4) Iran and Iraq have quietly, but most significantly, started to restore production; (5) Mexican production of gas and oil is up; (6) Soviet production estimates for the 1980's have been dramatically increased by the CIA, thereby increasing world supply; and (7) the pattern of the first two major OPEC price increases in 1973-74 and 1979-80 has shown

> that periods of declining or constant real crude prices follow sharp increases in oil prices, as the price of all other goods and services readjusts to the new crude prices. This is called inflation. This ratchet, or step-wise relationship just described, may be a better guide to 1982 price patterns than the approach selected by witness Mattson. This would support a relatively constant real oil price pattern for next year."

TURN's position on this issue is of interest. TURN basically believes that the staff estimate of market prices of fuel oil is too high. However, it supports the staff's marginal energy costs because they more closely encompass the social costs as well as the market prices of fuel oil.

We find the arguments and evidence presented by PG&E and CRA persuasive and will adopt PG&E's estimate of the projected price of fuel oil.

The resolution of the issues discussed above results in the Commission's adopted marginal costs shown below in Tables X-2 and X-3.

Table X-2

Pacific Gas and Electric Company
Electric Department

SUMMARY OF ANNUAL MARGINAL COSTS
BY VOLTAGE LEVEL
(1982 Dollars)

Line No.	Voltage Level	Annual Marginal Cost
	Transmission	
1	Demand ($/kW/year)	$ 92.52
2	Generation	76.56
3	Transmission	15.96
4	Energy (¢/kWh)	8.73
5	Customer ($/customer/year)	944.00
	Primary Distribution	
6	Demand ($/kW/year)	137.16
7	Generation	78.72
8	Transmission	16.44
9	Primary Distribution	42.00
10	Energy (¢/kWh)	8.89
11	Customer ($/customer/year)	369.00
	Secondary Distribution	
12	Demand ($/kW/year)	190.92
13	Generation	80.52
14	Transmission	16.80
15	Primary Distribution	43.08
16	Secondary Distribution	50.52
17	Energy (¢/kWh)	9.02
18	Customer ($/customer/year)	182.00

Table [illegible]3

Pacific Gas and Electric Company
Electric Department

SUMMARY OF MONTHLY MARGINAL COSTS BY VOLTAGE LEVEL AND BY COSTING PERIOD (1982 DOLLARS)

Line No.	Voltage Level	Period A On-Peak (A)	Period A Partial-Peak (B)	Period A Off-Peak (C)	Period B On-Peak (D)	Period B Partial-Peak (E)	Period B Off-Peak (F)	Customer (G)
	Transmission							
1	Demand ($/kW/month)	$11.83	$3.99	$0.01	$1.53	$0.39	$0.00	
2	Generation	9.78	3.30	0.01	1.27	0.32	0.00	
3	Transmission	2.05	0.69	0.00	0.26	0.07	0.00	
4	Energy (¢/kWh)	9.12	8.67	8.31	9.20	9.04	8.68	
5	Customer ($/cust./month)							78.67
	Primary Distribution							
6	Demand ($/kW/month)	13.63	5.71	1.54	2.39	1.40	0.89	
7	Generation	10.06	3.39	0.01	1.30	0.33	0.00	
8	Transmission	2.10	0.71	0.00	0.27	0.07	0.00	
9	Primary Distribution	1.47	1.61	1.53	0.82	1.00	0.89	
10	Energy (¢/kWh)	9.33	8.85	8.44	9.38	9.21	8.81	
11	Customer ($/cust./month)							30.75
	Secondary Distribution							
12	Demand ($/kW/month)	15.70	7.79	3.42	3.43	2.65	1.98	
13	Generation	10.29	3.47	0.01	1.33	0.34	0.00	
14	Transmission	2.15	0.73	0.00	0.28	0.07	0.00	
15	Primary Distribution	1.50	1.65	1.57	0.84	1.03	0.91	
16	Secondary Distribution	1.76	1.94	1.84	0.98	1.21	1.07	
17	Energy (¢/kWh)	9.52	9.01	8.55	9.54	9.36	8.92	
18	Customer ($/cust./month)							15.17
19	Hours per period per month	127.2	231.2	376.0	84.0	270.0	372.9	

5. Allocation of Revenue Requirement

The use of short-run marginal costs as our rate design foundation resolves many of the issues surrounding the allocation of the revenue requirement among the customer classes. The next question is what subset of the total set of marginal costs will be used in the allocation methodology.

We have used the EPD of allocation method in several general rate cases. All of the parties were familiar with this method and we will continue our practice.

The remaining question is what marginal costs will be used to allocate the revenue requirement? At this point, it is helpful to refer back to Table X-2. Several parties (CMA, CRA, Farm Bureau, and Industrial Users) are in favor of including every item of marginal cost shown in Table X-2 to allocate the revenue. Staff and PG&E, however, recommend that we eliminate those that are least sensitive to customer usage. This explicitly follows our policy in the last SoCal Edison general rate case (D.92549) in which we decided this very issue. Referring to Table X-2, staff and PG&E recommend that we use the items on Energy, Demand Generation, and Demand Transmission.

The advocates of total marginal costs argue once again that each item represents a cost incurred by the utility and therefore should be reflected in the allocation procedure. They argue that to eliminate any item would distort the allocation and send an incorrect price signal to consumers.

These arguments all assume a long-range perspective. If we were using a long-range view, we would indeed adopt the position advocated by PG&E by applying the same reasoning we used in the SoCal Edison D.92549 as follows:

> "Changes in rate design should reflect an application of marginal cost principles to those sectors of utility operation which are significantly affected by customers' decisions to limit or increase energy conservation. To the extent the utility's revenue requirement can be met by assessing rates no higher than marginal generation and transmission costs, no customer class will be penalized and appropriate price signals will be provided to encourage conservation. The emphasis on marginal generation and transmission costs is fully consistent with marginal cost principles in effect in our design of natural gas rates where alternative fuel costs and marginal purchased gas cost play an important part. Consistency in our energy rate design programs will also provide proper price signals to customers deciding on forms of energy utilization."

However, as discussed previously, we have chosen to use a short-run perspective for ratesetting in this proceeding. With this perspective, we adopted the following equation:

MC = Marginal Operating Costs - Shortage Costs

From this equation the items from Table X-2 which we will use are the marginal energy costs plus the marginal demand generation costs at each voltage level.

Employing these marginal cost elements with the EPD method, we can allocate the revenue requirement among the customer classes. The results are shown in the following table.

Table X-4

CLASS ALLOCATIONS

PACIFIC GAS AND ELECTRIC COMPANY

$000's

Class	A Sales GWH	B Present Base Revenue	C SRMC Base Revenue	D Increase	E Authorized Base Revenue (B+D)
Residential	18,713	470,652	1,288,764	203,652	674,304
1st Tier	10,668	268,301	734,705	116,101	384,402
2nd Tier	4,589	115,424	316,044	49,940	165,364
3rd Tier	3,456	86,927	238,015	37,610	124,537
Light and Power					
Small	4,922	163,803	341,882	44,329	208,132
Medium	13,118	324,584	899,261	143,054	467,638
Large	14,149	247,373	926,207	168,981	416,354
Agriculture	3,606	85,639	245,208	39,721	125,360
Railway	245	3,412	15,791	3,081	6,493
Subtotal Major Class	54,753	1,295,463	3,717,113	602,819	1,898,282
Public Authority	479	8,924	.	4,152	13,076
Lighting	372	25,141	.	11,699	36,840
Interdepartmental	124	2,834	.	1,319	4,153
Other	0	61,277	.	547	61,824
DWR	.	.	.	0	
Subtotal	55,728	1,393,639	3,717,113		
Adjustment		(1,115)			
TOTAL CPUC	55,728	1,392,524	3,717,113	620,536	2,013,060

In this proceeding TURN argued that other major customer classes should share some portion of the lifeline burden for two reasons. The first argument is that when lifeline was first implemented all classes shared the lifeline responsibility and this should remain unchanged. The second argument is that the residential class is the only class that faces inverted three-tier rates in order to encourage conservation. TURN feels that the other classes should share some of this burden.

TURN's arguments do not offer a substantial-enough basis for shifting any revenue requirement out of the residential class.

We note, however, that in A.60225, TURN has a proposal to use marginal rates in establishing rates. We are keenly interested in TURN's proposal which offers a more solid theoretical foundation for shifting some of the residential revenue requirement out of the residential class.

Steel Companies

As a subissue in the area of allocation, three steel companies (U.S. Steel, Judson Steel Co., and Soule Steel Co.) raised a general economic impact argument. The basic position argued by both the steel companies and the Industrial Users is that our rate allocation procedures have resulted in high rates for industrial users placing them at a competitive disadvantage with similar industries in other states. They request that we take economic results into account in our decision regarding allocation.

We could not be more aware of the economic consequences of our decisions. We are accosted every day by newspaper accounts of the economic conditions of the State. However, when presented with an argument by a special interest, such as the steel companies, we have none of the necessary facts, as follows:

1. Current state of production facilities of both the California industry and out-of-state industry.
2. Total costs of doing business in California versus out-of-state costs, such as:
    a. Labor
    b. Taxes
    c. Transportation
    d. All Other
3. Special advantages of either in-state or out-of-state (i.e., mine-mouth operations, climate, available labor pool).
4. Standard of living in-state versus out-of-state.

This brief list shows the complexity of analysis required to look into the specific economic effects of our decision on particular consumers. In fact, if we were to embark on such an investigation for the steel industry, would we not in all fairness need to make such an investigation into all industries? The policy could even be extended to identify the economic effect on residential consumers.

This course of action is clearly impossible. We have chosen marginal costs as our foundation for allocation and rate design. We have used marginal costs to promote economic efficiency and to provide the so-called greatest good for the greatest number.

6. Rate Schedules

We now consider the proposals and issues surrounding specific rate schedules. Rather than recapitulating the evidence and recommendation of each of the parties, we will center our discussion around each of the rate schedules.

Residential

Elimination of $1.75
Monthly Customer Charge

PG&E proposed to eliminate the monthly customer charge in order to send a better conservation signal to consumers in the form of more responsive energy charges. Also, PG&E points out that the customer charge is a source of confusion and dissatisfaction to consumers. The revenue contribution ($1.75) is also insignificant when compared to marginal customer costs ($15). PG&E was strongly supported by the Energy Commission and TURN. TURN also proposed that PG&E institute a minimum bill of perhaps $1.50 per month so that zero usage customers would make some revenue contribution.

The staff, on the other hand, proposed that the present customer charge be retained in order to reflect some of the customer costs in the residential bill.

TURN's concept of a minimum bill has merit. A minimum bill will mitigate the inequitable benefits received by zero usage residences in the absence of a customer charge. We will provide for a minimum bill of $2.00.

Inverted Three-Tier Rates

The issues surrounding the residential rates concern the degree of inversion and the size of the tiers. Also, a major unstated, but related issue, is whether the three-tier structure is more beneficial than the previous two-tier structure. The answer is provided in an exchange between counsel for the Farm Bureau and PG&E's rate design witness Reynolds at transcript page 5270, as follows:

> "Q Do you have any opinion on whether the conservation effect of the three-tier versus the two-tier method, which one was better?
>
> "A The evidence that I have seen to date from our elasticity studies, these have been presented for gas in the gas remand case, they are still being formulated, for the electric department, but the evidence strongly suggests that a three-tier approach does seem to induce conservation above and beyond elasticity developed based upon an average price variable.
>
> "I think that's a significant to me indicator that this particular type of rate design is an effective conservation inducing tool."

We are convinced that the three-tier structure by itself contributes significantly to conservation. We will therefore certainly continue it.

By D. 92656, we authorized PG&E to institute levelized base rates with the effective rate inversion maintained by the ECAC rate structure. No evidence was presented to suggest a change. The levelized base rates will be maintained.

PG&E has proposed that in order to provide greater rate design flexibility, we adopt a range of 35% to 45% differential between tiers rather than our present 38% differential. We agree that a range should be provided but that the range should be 30% to 40% in order to prevent too steep an inversion.

Another problem with the residential rate structure is the size of the tiers and their method of construction. Presently the usage allowed in the first tier is the lifeline amount which ranges from 240 KWh to 1,550 KWh a month depending on various climatic and end-use considerations. The present second tier, rather than a certain amount for all customers, is two times the lifeline allowance. The resulting problems were set forth in Exhibit 12B, page SPR-7, as follows:

"Q 9 What conclusions did you draw from your analysis of the three tiered electric rate structure?

"A 9 The analysis shows that, aggregate over all residential bills, the distribution of electric bills terminating in each tier is evenly distributed. However, bills for customers with extended allowances tend not to fall in the latter tiers. In fact, while only 28.7 percent of bills of basic allowance customers terminate in the first tier, 59.6 percent of extended allowance customer bills terminate in the first tier. Further, customers with a basic lifeline allowance and those who have a basic-plus-air conditioning allowance, whose usage terminates in the third tier, tend to extend further into the third tier than those with water and space heating allowances whose bills terminate in the third tier. As a result, the third tier allocation mostly affects customers with basic and basic-plus-air conditioning allowances.

"One reason for this impact is that the length of the second tier is, in all cases, equal to the lifeline allowance. Customers with basic allowances need only exceed their lifeline allocation by 240 kWh to be consuming into the third tier, while customers with, for example, electric water heating can use an additional 490 kWh before being priced at third tier rates.

"In addition, the size of extended allowances appears to increase the likelihood that a customer with such an allowance will not consume into the latter tiers. This suggests that the extended lifeline allowances may be disproportionately large relative to the end uses they serve when compared with the calculation underlying the setting of the basic allowance."

We find that the residential usage blocking of the three tiers should be as follows:

Tier I - Lifeline quantity.
Tier II - The next 300 kWh over lifeline quantities.
Tier III - Usage over Tier II.

This rate structure will distribute usage more evenly into all three tiers of the extended lifeline customers, thereby sending more correct conservation signals to these customers. Also, this blocking greatly increases equity among the residential groups.

Experimental TOU
Schedule (D-7)

PG&E has proposed to offer an experimental voluntary TOU rate to high-use residential customers to allow them to shift their consumption from higher to lower cost periods. The experiment will be limited subject to meter availability. PG&E has not set forth a plan for allocation of meters among customers, but has deferred to us to set priorities.

TURN opposes this schedule until a further study has been conducted. The staff proposes certain changes in the schedule to make it attractive only to families with solar devices.

We strongly disagree with TURN and applaud PG&E's efforts to provide residential customers with more options of service and rate combinations. We strongly believe that customers should be able to exercise more control over their utility bills.

Evidence in this proceeding has shown a degree of inequity caused by our inverted rates to large households. To mitigate some of these inequities, we believe that the tariff should be made attractive and practical to high-use families with or without solar devices. Of course, to continue to provide incentives for solar use, large families with solar devices should be given priority.

We will authorize proposed Schedule D-7 on an experimental basis. We direct PG&E to file a plan with the Commission within 120 days for the implementation of the schedule. The rate should be offered to customers in the following order.

1. Customers with a solar heating device and more than six members in the household.
2. Customers without a solar heating device and more than six members in the household.
3. Customers with a solar heating device and fewer than six members in the household.
4. Customers without a solar heating device with fewer than six members in the household.

Master Meter Adjustment

PU Code Section 739.5 states that master meter customers must be compensated for providing master meter service. This compensation has historically been provided by a discount to the providers of master meter service. The present discount is 26% of lifeline service on Schedule DT and $1.75/unit on Schedule DS.

The Western Mobilehome Association argues that the compensation should be increased based on an inflation factor. The staff believes that it should be maintained at the present level. No substantial evidence was introduced to justify increasing the level of compensation.

Eliminating the customer charge affects both DS and DT master meter compensation. In order for the compensation to remain at the present level, the DS and DT schedules should be modified in the following manner:

For Schedule DS, the $1.75 per unit must now be explicitly stated as a discount since the customer charge is being eliminated. We will order PG&E to provide this discount.

For Schedule DT, a discount of $4.70 per unit should be provided. This level of compensation was used in D.89907, dated January 3, 1979 (C.10273) to establish Schedule DT for PG&E, and has been maintained in subsequent rate orders for PG&E. We will order PG&E to provide this discount.

Light and Power Rates

Before proceeding further into specific light and power rates, it is helpful to discuss the general concept of demand charges and to a lesser extent customer charges. PG&E generally characterizes its rate philosophy as moving toward time-differentiated energy rates with less emphasis on demand and customer charges. To maintain load management incentives and because of historical precedents, demand and customer charges are retained and many are increased somewhat in several of the light and power schedules. The staff, on the other hand, recommends that present demand and customer charges be retained at present levels.

Energy Commission strongly argues that both customer charges and demand charges should be eliminated totally or at least reduced substantially. The evidence tends to substantiate the Energy Commission's premise that marginal capacity costs are driven by energy use as well as maximum demand. The next step of the argument is contained in Exhibit 117, page 9, as follows:

"The key to both load management and conservation is to reduce energy use. Reducing system peak is accomplished by reducing energy use of individual customers at the time of system peak, not reducing noncoincident demand. This phenomena is also called increasing diversity of individual loads. Time-of-use energy rates may not penalize customers for their noncoincident peak, but will encourage greater energy conservation and hence diversity. Rates with lower demand charges and more time differentiation in energy charges can show more load factor improvement and more load shifting from peak to off-peak periods than rates with higher demand charges and less time differentiation in energy charges."

Regarding customer charges, Energy Commission's witness testified that:

"Customer charges by their nature as a fixed monthly cost are inherently inefficient, because they do not reflect the cost of energy, and inequitable, because they penalize small energy users. While PG&E's rates are inverted to reflect increasing marginal costs, a fixed cost element in the tariff contradicts the intended price signal."

Other industrial customers generally oppose the Energy Commission. The CRA argues that demand charges better reflect demand costs particularly if the energy charge is not time-differentiated. The Industrial Users argue that demand charges can be an incentive to produce increased load factors which would increase plant efficiency. This is more desirable than decreased usage.

We are persuaded by the testimony of the Energy Commission. Because we do not feel that radical changes can be made in all of the light and power schedules at this time, the total recommendation cannot be adopted.

Small Light and Power

PG&E proposes to increase the energy, customer, and connected load charges for the A-1 schedule. We will authorize only an increase of the energy rates. The staff proposals regarding both A-1 and A-15, a direct current tariff, will be adopted.

Medium Light and Power

Staff and PG&E agreed that certain experimental rates (S-1, A-20A, A-20B, A-20C, and A-20D) should be changed. No other party proposed changes. The PG&E proposal will be adopted.

PG&E has proposed to implement a new customer charge and to increase the demand charges for the A-12 schedule. The A-12 schedule, a demand metered general service schedule, includes the bulk of the medium general service sales. Also, it contains a demand ratchett feature which bases the demand charge on the highest demand during the previous 12 months. The CRA endorses the PG&E proposal.

The staff recommends retention of the present demand charge and elimination of the demand ratchett feature. Also, the staff opposes the addition of the new customer charge. We agree with and adopt the staff recommendations.

The A-21 schedule is a TOU demand metered schedule mandatory for customers with peak demands above 500 KW. This schedule was the subject of a separate Commission proceeding (A.58089) which was decided after this application was filed. We will retain the relatively low demand charge of $1 per KW provided by D.92553. Also, the staff recommends that this schedule be optional for customers below 500 kW. This recommendation was uncontested and will be adopted.

Large Light and Power

Large light and power customers are served primarily by three schedules: A-18, A-22, and A-23. A-18 is the schedule for interruptible customers; A-22 is for customers with monthly demand between 1,000 and 4,000 kW; and A-23 is for those with demand in excess of 4,000 kW.

In this proceeding PG&E proposes that the A-22 and A-23 schedules be combined. The combination would feature increased customer and demand charges with greater increases of the energy charges. The resulting schedule would contain common energy, demand, and customer charges. Although the schedules would have the same rates and charges, they would be separately maintained in order to examine future load characteristic cost variations. The proposal is founded on the concept that the marginal cost of producing the last unit of energy is the same for both classes of customers.

The staff position is that PG&E has not demonstrated the need for any such change. The staff proposes rather an increase of the energy charges of each schedule with no change in the demand or customer charges. This is supported by CRA on the theory that because A-22 and A-23 are TOU rates, the increases should be in the energy rates.

The Industrial Users strongly oppose PG&E's proposals on two grounds. First their arguments concern the emphasis on energy rather than demand and customer charges. We have resolved this in our previous discussion concerning light and power rates above. Second, the Industrial Users claim that the load characteristics of customers in the two schedules are very different. PG&E countered that most of these differences were caused by a few large atypical customers and that but for those customers, the average cost characteristics of the A-22 and A-23 customers would be more nearly equal.

We are persuaded by the testimony of PG&E and will authorize the consolidation of the A-22 and A-23 schedules. However, rather than increasing the customer and demand charges, the consolidated schedule will contain the lowest of the customer and demand charges presently in effect on either schedule.

Interruptible Rates

Interruptible rates are designed to reduce system peak load at times of low reserve margins, thereby deferring need to build expensive new generating capacity. Customers on interruptible tariff schedules are given a discount as compensation for the possibility of interruption.

During the course of this proceeding, PG&E amended its interruptible rates by Advice Letter 851-E to make them more attractive. The staff notified PG&E by letter on April 8, 1981 that the tariff has been approved on an experimental basis subject to filing of a preliminary report before October 1, 1981 and a final report before October 1, 1982 evaluating the cost-effectiveness of the new rates. We concur with this treatment and will order filing of the final report in this decision.

Street and Outdoor Lighting

PG&E originally proposed a uniform cents per kWh increase for the street and outdoor lighting schedules. The staff and the City of Oakland recommended uniform percentage increases. In its brief, PG&E accepted the recommendation for a uniform percentage increase. The staff's recommendation regarding street and outdoor lighting schedules (LS-1, LS-1A, LS-2, LS-3, OL-1, and TC-1) will be adopted.

Agricultural Rates

The agricultural rate proposals are basically not at issue in this proceeding. The staff's recommendation, as suggested by the Farm Bureau, will be adopted for the agricultural rate schedules (PA-1, PA-1X, and PA-2X).

B. Rate Design - Gas Department

1. Background

The gas rate design is not as controversial as electric rate design because we have previously decided many of the relevant issues. Gas rate design has as its foundation two elements: (1) the priority system, and (2) alternate fuel pricing. Because of this particular foundation of gas rate design, the issue of allocation of the revenue burden has been virtually eliminated. Specific rates can be designed directly from the revenue requirement if rates are based on these two elements. This process leaves at issue how we will adopt and apply a limited number of explicit guidelines to arrive at the rates.

Our previous guidelines involved ratesetting for the lower priority customers (P-3, P-4, and P-5) served on the G-50, G-52, G-55, and G-57 schedules based on the price of the alternate fuel source, and for the remaining customers based on a relationship of the class rates to the system average rates. In setting the various rates, we have necessarily used effective rates; that is, the sum of the rates decided in general rate proceedings and the rates decided in purchased gas offset (GAC) proceedings. Because the rates are changed at every GAC proceeding as purchased gas costs change, and because these costs are such a high percentage of the total cost, the most important function of general rate cases is to establish guidelines and rate relationships.

2. Marginal Cost of Gas

Because we rely heavily on marginal costs in establishing rates for electric service, we feel it necessary to comment on the marginal cost concepts for gas pricing. We do rely heavily on marginal cost concepts to price gas, contrary to the views of some of the parties to this proceeding.

PG&E basically states that marginal cost methodology for gas is in its infancy, and is undergoing study and development. The staff argues against the use of marginal cost pricing for basically the same reasons that embedded costs advocates argue against marginal cost pricing in electricity. TURN, on the other hand, argues that the same basic marginal cost equation is applicable to both gas and electric pricing.

We believe that TURN is correct. Once we have determined that the short-run marginal costs are appropriate for pricing, the same basic equation evolves:

MC = Marginal Operating Costs + Shortage Costs.

Admittedly, the shortage costs term in the equation has not been studied carefully. But because the use of marginal operating costs can generally match the marginal costs with the revenue requirement, the shortage costs can be ignored for the moment. This leaves the single term of marginal operating costs which are the marginal energy costs or more basically the price of alternate fuel oil as explained in Exhibit 16 at page 2-8:

> "For the smaller increments and decrements, the marginal cost of gas more closely approximates residual fuel oil; in fact, it appears that for smaller and smaller demand changes the marginal cost of gas will converge to the cost of residual fuel oil. These are reasonable results in light of PGandE's gas resource planning criterion that the cost of future gas resources must be less than the projected cost of alternate fuels in the long run. Furthermore, since natural gas which is 'freed up' through conservation on the part of PGandE's firm gas customers may be used by PGandE's non-firm gas customers. The gas can be sold to curtailable customers at their alternate fuel costs, which for the lowest

> priority users is the cost of residual fuel oil. In this way, one can think of the marginal 'opportunity' cost of conserved gas as the price at which that gas can be sold elsewhere. Because of these several reinforcing reasons, PGandE has chosen to use the forecasted cost of residual fuel oil as the long-run marginal commodity cost of gas for use in the evaluation of the cost-effectiveness of the Company's gas conservation programs."

One can now at least view electricity and gas pricing in the same terms. In fact, marginal gas pricing probably has a longer history than marginal cost pricing for electricity. Also, gas pricing has, as a strong foundation, the priority system whereby various classes of customers are assigned a priority depending on end-use and alternate fuel capability. With this foundation in mind, it is clear that we have historically attempted to price the gas for low priority customers closer to marginal costs than the gas for high priority customers. On the electric side, we have attempted to bring each class of customers equally close to its marginal cost.

Once low priority gas customers are priced at marginal cost, it is clear that the remaining high priority customers will be responsible for matching up the remaining prices and the revenue requirement.

3. Gas Rate Design

Gas rate design was much less contested in this proceeding than was electric rate design. The proposals of the parties were not far apart and the additional revenue is relatively small compared to the Electric Department. In addition, we have previously settled many rate design issues.

PG&E

In this application PG&E proposes to eliminate the residential customer charge, increase the small commercial (G-2) customer charge from $1.20 to $3.00, and spread the revenue increase among the residential and small commercial classes. It also proposes to restructure the residential rate schedules by splitting the lifeline tier into two equal usage blocks and continuing the present second and third tiers. PG&E proposes the retention of the guidelines previously set forth in D.91720 as amended.

Staff

The staff of the Gas Branch of the Commission makes the following recommendations in Exhibit 39:

1. Retain the residential monthly customer charge.
2. Defer residential usage blocking to OII 77.
3. Serve large commercial-industrial (P-3, P-4, and P-5) customers under Schedules G-52, G-55, G-55A, and G-57; reference rates to the current market price for #6 low sulfur fuel oil. Set Schedule G-50 rates to be at a premium above G-52.
4. Use these guidelines for residential and G-2 rates:
   a. Set the average residential rate and the G-2 rate should be set at the same level and by reference to the system average rate.
   b. The lifeline residential rate should be approximately 10¢ per therm less than the average residential rate and recover, as a minimum, the average cost of gas.

c. The nonlifeline residential rate should be set residually after determining the residential revenue requirement, and the customer month and lifeline revenue contributions.

These guidelines parallel the Southern California Gas Company (SoCal Gas) guidelines.

4. In summary, the recommended guidelines for resale rates are:

   a. A single commodity rate schedule.

   b. The Palo Alto Schedule G-60 rate equated to 85% of the system average rate.

   c. The other resale customers' (schedules G-61, G-62, and G-63) commodity rate be defined as the sum of the average cost of gas, the margin, and the Gas Exploration and Development Adjustment (GEDA) rate. This will not preclude the addition of any adjustment rate authorized by the Commission.

The staff of the Policy and Planning Division in Exhibit 91 provided testimony and made the following recommendation regarding rate design criteria:

> "The recommended criteria are: (a) rates for interruptible service under Schedules G-52, G-55 and G-57 should be uniform and referenced to the cost of alternative No. 6, low sulfur fuel oil to PG&E; (b) the Schedule G-50 rates should be continued at a level not exceeding 3¢/therm above the G-52, G-55, and G-57 rate; (c) the Schedule G-2 rates should be referenced to the average system rate (less lifeline sales and revenues) for small customers. Feasibility of an inverted rate should be examined pursuant to the ruling of the Administrative Law Judge. We should examine the feasibility of pricing large G-2 users on a basis consistent with the rates to interruptible customers; (d) the lifeline rate should not be more than 25% below the

> average system rate. If the customer charge is eliminated, the lifeline quantity rate should be equivalently increased; (e) the maximum residential rate should not exceed the marginal supply costs and the Tier II rate should not exceed the Schedule G-52 rate; and (f) the average rate for the residential class should not be more than 7% below the system average rate (approximately the present rate relationship)."

Energy Commission

Energy Commission's participation in gas rate design was limited. Its two recommendations were that: (1) the monthly customer charge be eliminated in both residential and nonresidential tariffs, and (2) we should further study the relationship of gas rate structure (usage blocking) and ZIP.

TURN

TURN's position in this proceeding was similar to that of the Policy and Planning Division. TURN does argue that the G-52 and G-55 rates need not always be equal.

Industrial Users (GM)

General Motors Corporation filed a separate brief which strenuously argues that the G-2 rate guideline should not be referenced to the G-50 rate. GM offered no evidence but cites past Commission decisions.

Palo Alto, Coalinga

Each of these cities requested that the Commission pay attention to their unique characteristics and situations in determining the resale rates (G-60, G-62, and G-63).

Discussion

This brief summary of the major parties' positions indicates the issues to be resolved. The monthly customer charge is the first topic of discussion.

Customer Charge

Both PG&E and the Energy Commission provided testimony supporting the elimination of the residential customer charge. Its elimination was also supported by TURN, but was opposed by the staff. Its elimination would promote conservation by placing the associated revenue requirement into the commodity rates and reducing customer confusion.

The staff argued that the elimination would increase bills in the winter when usage is greater and reduce them in the summer when usage is lower.

We will adopt PG&E's proposal to eliminate the residential customer charge. This is consistent with our decision on the electric residential customer charge.

The Energy Commission testified that eliminating the customer charges for small commercial users (G-2) would similarly promote conservation in this sector also. PG&E states that this would have a minuscule effect on the commodity rates. Also, PG&E provided testimony that zero usage customers did not have the same degree of customer confusion PG&E, therefore, argued that the nonresidential customer charge should be not only retained but actually increased in order to provide greater revenue stability.

There was insufficient evidence to show that more revenue stability is required than that provided through the GAC procedure. As PG&E points out, the customer service charge revenue is a minuscule portion of the total revenues generated by the G-2 schedule - 1/3 of 1%. We will therefore eliminate the G-2 customer charge.

Residential Usage Blocking

The next issue to be discussed concerns PG&E's proposal to split the lifeline block into two equal blocks and to consolidate the second and third tiers. The proposal is designed to promote conservation by making the usage in each block more similar. The current sales percentages are 73% in Tier I, 21% in Tier II, and 6% in Tier III. PG&E's proposal would result in 27% in the tail block, thereby sending a better conservation signal to a greater number of customers.

The problem is somewhat analogous to the usage blocking problem that we addressed regarding the electric rates. However, here the problem involves the size of the first tier rather than the method of defining the second and third tiers. In this proceeding we are not prepared to consider different lifeline quantities. Because the rate relationships we will adopt will be in terms of lifeline versus nonlifeline, we do not feel that splitting the lifeline tier will solve the more basic problem of how to better construct first tier usage quantities. We will therefore reject the proposal to split the lifeline tier and consolidate the second and third tiers. We feel that OII 77 is the proper forum for these proposals. Also, we agree with the Energy Commission that any change in the present structure must be analyzed in terms of the effect rate structure has on ZIP.

4. Rate Guidelines

Our rate application guidelines to PG&E were generally established in PG&E's last general rate case. These guidelines covered (1) the sequence of application, (2) resale rates, (3) the G-2 reference rate, and (4) the relationship of the lifeline and non-lifeline relationship to the system average rate. Most of the parties showed some confusion regarding the present guidelines. We will attempt here to establish a step-by-step method of setting the individual rates.

Guidelines may be applied either simultaneously, or sequentially. Our previous guidelines were applied simultaneously with a great degree of judgment reserved for us. Rate design became an issue in GAC proceedings because no party had a clear idea of the resulting rates. This problem will be remedied with a definite sequence to application of the guidelines, as recommended by the Policy and Planning Division witness and strongly supported by TURN.

Before discussing the sequence, we must first be absolutely clear on our rate guidelines.

Resale Rates

The resale schedules are provided for the following customers: Palo Alto (G-60), City of Coalinga (G-61), CP National Corporation (G-62), and Southwest Gas Corporation (G-63). The basic formulas for setting the G-62 and G-63 rates have long been established and were not contested in this proceeding. They will not be changed except for changing the rates to a single commodity rate as recommended by the staff.

The City of Coalinga also has had a long-established rate-fixing formula, but in this proceeding Coalinga argued that its gas should be priced as if it were only purchasing California gas. Coalinga's secondary position is that a new sales profile should be adopted.

Coalinga's first position is totally without foundation. Nowhere have we stipulated that PG&E should price the gas as if it came from a particular source, a so-called cost of service rate. Also, Coalinga failed to provide sufficient evidence for us to change its sales profile. The historical formula for setting Coalinga's gas rates will be retained except that the rates will be consolidated into a single commodity rate as recommended by the staff.

Palo Alto presented evidence that the present formula for setting its rates has resulted in an inadequate margin because of its very effective conservation efforts. Palo Alto, therefore, requests that a new formula be adopted. Palo Alto proposes that the G-60 rate be 80% of the average rate paid by PG&E's P-1 and P-2 customers. The staff proposed that the G-60 rate be set at 85% of the system average rate.

The problems surrounding the Palo Alto rates were well-chronicled in our previous decision (D.89315, September 1978). PG&E has not yet presented a satisfactory rate formula. The proposal of the staff is easily administered and produces a satisfactory margin to Palo Alto. Our basic policy that Palo Alto be allowed a reasonable margin without our entering a mini rate case for Palo Alto has been consistent for a number of years and remains unchanged.

For this proceeding we will adopt the staff's recommended formula. We believe that this formula will produce satisfactory results through at least one or two GAC offset proceedings. We are adopting guidelines which result in an average rate for P-1 and P-2 customers which is less than the system average rate. Palo Alto establishes its gas rates at the same level as PG&E rates and does not have the substantial low priority market available to PG&E. In subsequent GAC proceedings, if Palo Alto is unable to maintain a reasonable margin, we will reexamine the ratio used.

Industrial Rates (G-50,
G-52, G-55, and G-57)

The industrial rates serve P-3, P-4, and P-5 customers which must have alternate fuel capability. The G-50 customers must have the ability to burn #2 low sulfur fuel oil. The remaining industrial customers must have the ability to burn #6 low sulfur fuel oil. Our current policy that the G-52, G-55, and G-57 rates should be uniform and referenced to the market price of #6 low sulfur fuel oil will not be changed. Also, we will retain the guidelines setting the G-50 rate at not more than 3 cents per therm above the G-52, G-55, and G-57 rates.

Commercial (G-2)

The G-2 schedules serve customers in the P-1, P-2, and P-2A classes. Our current guideline is that the G-2 rate be referenced to the system average rate excluding lifeline sales and revenues. The Policy and Planning Division witness testified that the G-2 rate should be set at the same level as the G-50 rate because many of the G-2 and G-50 customers have comparable usage levels and some have the same types of end uses. The G-2 customers are paying a lower rate because they do not have alternate fuel burning capability, but it is reasonable that all rates be moved closer to marginal costs.

We basically agree with the position advocated by the Policy and Planning Division's witness Cavagnaro. However, because of our decision regarding a sequential application of guidelines, the final G-2 rate should be set within a reasonable range. Therefore, the target rate for the G-2 schedule is the same level as the G-50 rate; however, in the resolution of over- and undercollections, the G-2 rate can fall within a range of plus or minus 3% of the G-50 rate. These parameters will serve as a signal that our guidelines should be reexamined if the resulting G-2 rates exceed the 3% allowance.

Residential Rates

We intend to set the residential rates residually. Since the residential customers, like the G-2 customers, do not have alternate fuel burning capability, these rates need not be capped at the price of #6 or #2 low sulfur fuel oil.

We are satisfied with the present rate relationships between the lifeline rate, system average rate, and the residential class average rate. The recommendations of the staff of the Utilities Division, which uses a cost of service basis for setting residential rates, will be rejected. We have previously decided that the average cost of service is not an appropriate standard for setting gas rates.

The guidelines we adopt are that: (1) the residential class average rate can be no more than 10% below the system average rate, (2) the Tier III rate will be set at 70% above the class average rate, and (3) the Tier II rate will be set residually.

Determination of Specific Rates

In order to let all parties know with some certainty how specific rates will be determined in this proceeding and in future GAC proceedings, we will establish an orderly sequence of steps.

Step 1. We will adopt a revenue requirement, a sales figure, and a reference price of low sulfur #6 fuel oil.

Step 2. The G-52, G-55, and G-57 rates will be set at the reference price of low sulfur #6 fuel oil in Step 1. The G-50 rate will be set at 3 cents per therm higher than the G-52 et al. rates.

Step 3. The G-2 class rate will be set equal to the G-50 rate. In other words, G-2 sales times the G-50 rate will equal the G-2 revenue requirement.

Step 4. The residential revenue requirement will be determined by multiplying residential sales times a rate which is 10% less than the system average rate.

Step 5. The resale rates will be established by the formulas which we have previously discussed.

Step 6. If at this point the revenue requirement is not met, the residential and G-2 rates will be increased by an equal number of cents per therm to meet the revenue requirement. The G-2 rate should not be greater than 3% less than the G-50 rate.

If excess revenue is produced, the G-2, G-50, G-52, G-55, and G-57 rates will be reduced by an equal cents per therm to meet the revenue requirement.

Step 7. Within the residential class are:

a. Tier I will be set 15% less than the residential class average rate.

b. Tier III will be set at a rate 70% above the class average rate.

c. Tier II will be set residually.

C. Attrition Year Revenue Allocation

Electric Department

As previously discussed, we have authorized an attrition allowance for 1983. To implement the rates quickly without further hearing, we will continue to authorize step rates as we have done for SoCal Gas and SoCal Edison.

The attrition allowance can be allocated among the customer classes in four ways. (1) As to use the current marginal costs as in the test year allocation, (2) to project the 1982 marginal costs, (3) to wait until next year's August or December ECAC proceeding to decide on the allocation issue, (4) to allocate the allowance on an equal percentage basis to the various customer classes. This is the most straightforward method.

We are presently inclined to use the final equal percentage basis in order to maintain the relationship among customer classes that we establish in this opinion. However, to preserve our options, we will defer a final decision on this issue until PG&E's 1981 reasonableness review ECAC proceeding.

Gas Department

With our firm guidelines on gas rate design, the implementation of the Gas Department attrition allowance becomes straightforward. We will allow PG&E to make an advice letter filing which follows our gas rate guidelines for attrition year rates to be effective January 1, 1983.

D. Relationship of GAC, ECAC, and General Rate Case

Now that we have resolved the issues of rate design and general rate case revenue requirements for both the Electric and Gas Departments, we could establish a specific set of new effective rates. However, at the time this decision is being issued, two other rate proceedings which involve PG&E would change these rates. An ECAC offset proceeding (A.60961) and (A.60863) a GAC offset proceeding are ready for decision.

The purpose of a general rate case is to establish base revenue requirements and base rates. The purpose of the offset proceedings is to establish the offset rates which pass through changes in fuel energy costs. The two rates added together (base + offset) then become the effective rates.

At this time all three proceedings are ready for decision. However, because changes in one decision affect the others, a sequence of events must be discussed.

The ECAC proceeding will establish a new ECAC rate which will be uniform among all customer classes. The effective electric rates can most easily be developed in the ECAC decision by carrying over to that proceeding the base rates that we have established in this case.

The gas offset proceeding will furnish an up-to-date sales figure, alternate price of fuel oil, and revenue requirement. Therefore, new effective rates will be set by carrying the revenue requirement developed in the general rate case to the GAC proceeding. We will also apply guidelines developed in the general rate case to the total revenue requirements of both cases in the GAC decision.

The gas offset proceeding will furnish an up-to-date sales figure, alternate price of fuel oil, and revenue requirement. Therefore, new effective rates will be set by carrying the revenue requirement developed in the general rate case to the GAC proceeding. We will also apply guidelines developed in the general rate case to the total revenue requirements of both cases in the GAC decision.

XI. Findings and Conclusions

Findings of Fact

1. PG&E filed this application in compliance with the requirements of Resolution M-4706 and the Commission's Regulatory Lag Plan.

2. The adopted 1982 test year estimate of PG&E's California jurisdictional electric results of operations under present rates is shown on Table VI-2. The indicated rate of return on rate base at present rates is 5.99%.

3. The adopted 1982 test year estimate of PG&E's Gas Department results of operations under present rates is shown on Table VII-2. The indicated rate of return on rate base at present rates is 6.14%.

4. The following capital structure and capital costs are reasonable for test year 1982 and attrition year 1983.

	Capital Ratios	Cost	Weighted Cost of Capital
Test Year 1982			
Long-Term Debt	45%	9.73%	4.38%
Preferred Stock	14	9.03	1.26
Common Equity	41	16.00	6.56
Total	100%		12.20%
Attrition Year 1983			
Long-Term Debt	45%	10.35%	4.69
Preferred Stock	14	9.40	1.32
Common Equity	41	16.00	6.56
Total	100%		12.57%

5. A 12.20% rate of return for test year 1982 and a 12.57% rate of return for attrition year 1983 on PG&E's CPUC Jurisdictional Electric Department and Gas Department rate bases incorporating a 16% return on common equity are fair and reasonable.

6. A 12.20% rate of return is expected to provide PG&E with a 2.79 times after interest coverage.

7. To earn a 12.20% rate of return in test year 1982, PG&E's base rates for electric service needs to be increased effective January 1, 1982 by $621 million and its gas rates by $203 million.

8. Although the change in PG&E's resource plan has resulted in a substantial reduction in capital requirements in 1981-1982, the capital requirements and associated external financing requirements remain quite substantial.

9. PG&E's three cash flow improvement proposals for adoption of a nonearning assets ratio, incremental depreciation, and ratable flow-through of the 6% portion of ITC would have increased revenue requirements by approximately $350 million in 1982.

10. The Tax Act requires the normalization of the tax benefits of ACRS depreciation and ITC if PG&E is to be eligible to use these tax benefits.

11. The Tax Act provides for a R&E tax credit and also eliminates the repair allowance.

12. Under the transitional rules in the Tax Act, the normalization requirement must be met no later than the first general rate case decision issued for PG&E after the enactment of the Tax Act.

13. This decision is the first general rate case decision issued for PG&E after the enactment of the Tax Act.

14. Under the current NOI procedure where utilities apply for a general rate increase every two years with an attrition adjustment made in the year following the test year, the features and goals of the AAA/AA method of normalization in recognizing the growth of the deferred tax reserve is recognized in the attrition year rate adjustment; therefore, full test year normalization is appropriate.

15. It is reasonable to adopt an estimated R&E tax credit of $1.8 million and $115,000 for the Electric and Gas Departments respectively for test year 1982.

16. The Tax Act has the effect of increasing PG&E's revenue requirements by approximately $177 million in test year 1982 and its cash flow by approximately $85 million.

17. If Diablo becomes operational in 1982 it will have the effect of increasing PG&E's cash flow by roughly $131 million and its revenue requirement by $262 million.

18. PG&E has failed to prove that cash flow improvements beyond those provided by the Tax Act are necessary.

19. A system of management incentives to encourage investments into preferred alternative resources and cost-effective conservation programs requires further study.

20. If development of preferred alternate resources is cost-effective, it is incumbent on PG&E's management to develop such cost-effective alternative resources rather than long lead time conventional resources that will require it to sell additional common equity below book value and further dilute the existing stockholder's equity.

21. Although PG&E and staff were far apart in their respective revenue and sales estimates for test year 1982 and attrition year 1983, they have agreed as to an estimate for this proceeding.

22. It is difficult to make reasonable estimates for appropriate sales and revenue levels since it is difficult to quantify the effects of conservation.

23. PG&E, Energy Commission, and the staff all agree that an adoption of an electric revenue adjustment mechanism is necessary to protect PG&E, as well as ratepayers, from any over- or underestimates of sales and revenues.

24. The adoption of an ERAM will eliminate any disincentives for PG&E to promote all cost-effective conservation programs.

25. The adopted ERAM set forth in Appendix D is reasonable and fair to both ratepayers and PG&E.

26. PG&E will be unable to earn its authorized return on common equity in attrition year 1983 without an attrition allowance due to increases in operating costs resulting from continuing high levels of

inflation, increases in the embedded cost of debt and preferred stock, and the increase in rate base by increased productivity.

27. PG&E will require additional revenues in attrition year 1983 for its California jurisdictional Electric and Gas Department operations, respectively, if PG&E is to earn its authorized 16 percent return on common equity.

28. It is difficult to accurately estimate the appropriate escalation factors for labor and nonlabor expenses for attrition year 1983.

29. The adoption of an indexing procedure for determining the 1983 attrition allowance is reasonable to protect PG&E, as well as the ratepayers, from over- or underestimates of the labor and non-labor escalation factors.

30. It is reasonable to adopt the staff's methodology of estimating rate base increases in the attrition year by use of five-year historical additions to plant per customer.

31. The ARA mechanism, set forth in Appendix E, providing for indexing of labor and nonlabor escalation factors and also showing the attrition year revenue requirement effect for increases in rate base, depreciation expenses, income tax, and financial attrition for 1983, is reasonable.

32. The rates of return on common equity and rate base together with the increased revenue requirements found justified for test year 1982 and attrition year 1983, are expressly authorized with the understanding that the next earliest test year to be used in establishing PG&E's total revenue requirements will be 1984. The rates of return are reasonable in view of our adoption of ERAM and ARA procedures, the existence of the ECAC, GCAC, and SAM procedures and the cash flow generated by the Tax Act.

33. It is reasonable to use the modified PPI developed by the staff for the purpose of escalating nonlabor expenses in this proceeding.

34. The adopted conservation and load management budget of $90.5 million, exclusive of programs for solar water heating, weatherization ZIP, and RCS, which are subject matters of special proceedings, is reasonable.

35. The adopted conservation program budget for 1982, included under Customer Service and Information Expenses, of $42,949,000 is reasonable and does not include budgets for programs which are the subject of separate proceedings.

36. The adopted load management budget for 1982 of $47,574,000 including both capital and operating expenditures, is reasonable.

37. It is reasonable to permit PG&E to reallocate funds within the residential, C-I-A, and load management programs of up to $2.5 million from a given program to be used in another existing or new program. Budget adjustments in excess of $2.5 million should be made the subject of an advice letter filing.

38. It is reasonable to resolve uncertainties in conservation evaluation methods by publicly noticed workshops to commence no later that February 16, 1982, and for staff, PG&E, and any other interested parties to submit specific evaluation methods based on the workshops along with supporting rationale.

39. PG&E's revised Phase II CVR program for 1982 is reasonable.

40. Although PG&E has failed to attain the 600 MW goal of new cogeneration required by D.91107, PG&E has taken useful steps to encourage cogeneration and small power production.

41. Various uncontrollable factors not considered in D.91107 have slowed down development of cogeneration projects.

42. It is reasonable to add an additional $10 million to the attrition adjustment for 1983 as determined by the ARA mechanism. This will provide adequate revenues to fund continued gradual increases in the scale of PG&E's energy conservation programs.

43. It is not necessary to set new goals for cogeneration projects at this time and to establish penalties based on such goals.

44. It is reasonable to resolve the issues relating to the definition and reporting of RD&D through a workshop sponsored by the staff and attended by PG&E and interested parties. PG&E's response to the CMP audit criticisms of its planning and management of RD&D will also be reviewed in workshops.

45. Since the issue of employee discounts is an issue affecting all public utilities, we will resolve this issue through an OII.

46. It is reasonable to include bank fees involved in establishing a line of credit to be recovered in base rates rather than included in the computation of an AFUDC rate.

47. It is reasonable to transfer the issue relating to the investment in the Diablo Information Center to the proceedings in A.58911 along with other Diablo rate base costs and for PG&E to accrue AFUDC on such investment.

48. It is reasonable to include the investment in Diablo corridor land and land rights of $6,468,000 in rate base since such land and land rights relate to facilities which have been a part of the grid for the last few years providing alternate routing and system stability.

49. It is reasonable to record the investment in Utah coal reserves together with any carrying charges in a memorandum account. If such properties are no longer to be used for utility purposes, PG&E should advise the Commission and make a recommendation as to the appropriate accounting and ratemaking treatment upon disposition of such properties.

50. It is reasonable to record the operation and maintenance expenses relating to the Humboldt nuclear plant together with applicable insurance expenses in the Humboldt memorandum account and accrue AFUDC on the balance pending resolution as to the future operating status of the plant.

51. It is reasonable to transfer the cost of the Humboldt nuclear fuel to the memorandum CWIP account and permit PG&E to accrue AFUDC on such investment until the ultimate disposition of Humboldt is decided.

52. It is reasonable for PG&E to seek recovery of Nuclear Department A&G expenses relating to Diablo in the Diablo offset proceedings.

53. PG&E should resolve the operating status of Humboldt by the time it files its next NOI for 1984.

54. It is reasonable for PG&E to include only short-term borrowings in excess of balancing account undercollections and short-term investments in calculating the AFUDC rate.

55. It is reasonable to exclude estimated Canadian take-or-pay payments from Gas Department rate base and to consider carrying costs related to take-or-pay payments in a GAC proceeding.

56. A conservation incentive program has the potential to stimulate greater productivity in utility conservation programs but there is insufficient evidentiary basis for adoption of such a program in this proceeding.

57. It is reasonable to require PG&E to submit a report on or before March 31, 1983 showing for 1982 the dollars budgeted for maintenance, the dollars spent, and the status of its maintenance program.

58. Because the cost of envelopes and postage is included in the development of revenue requirement, the "extra" space (now occupied by the Progress) in the envelopes used for billing and dividend checks is properly considered as ratepayer property. The "extra" space is the space remaining, after inclusion of the monthly bill, dividend check and/or legal notices, for inclusion of other materials up to such total envelope weight as will not result in additional postage cost.

58a. There is a cost to ratepayers as a result of PG&E's using the "extra" space in billing envelopes for mailing the PG&E Progress; there is no cost to ratepayers from PG&E's using the "extra" space for mailing the Progress to shareholders with dividend checks.

59. PG&E improperly recovers the cost of mailing its political advertising to ratepayers through its use of the extra space in billing envelopes because this practice allocates to PG&E, and deprives the ratepayers of, the economic value of the "extra" space in the billing envelope.

60. The most efficient means of capturing for ratepayers' benefit the full economic value of the extra space remains to be determined in a future proceeding.

61. It is reasonable to require PG&E to maintain records on its conservation fund expenditures on a program-by-program basis so that program expenditures may be separately identified, justified, and evaluated for reasonableness.

62. It is reasonable to revise the AER to $.00276 kWh to produce $10,684,000 in additional AER revenues in recognition of the 12.20% rate of return adopted in this decision.

63. There can be three means of calculating marginal costs: (1) short-run energy and short-run capacity, (2) short-run energy and long-run capacity, and (3) long-run energy and long-run capacity.

64. For ratesetting purposes, consumers should be signaled the present cost of consumption.

65. Short-run energy and short-run capacity costs are the correct way of conceptualizing marginal costs for ratesetting.

66. Short-run marginal costs equals operating costs plus shortage costs.

67. Operating costs equals marginal energy costs plus variable operating and maintenance costs.

68. Shortage costs can be proxied by the capacity costs of a gas turbine.

69. The gas turbine proxy for shortage costs will have a 24-year useful life and a 9.1% carrying cost.

70. Diablo will not be assumed operational for the purposes of computing marginal energy costs.

71. The price of residual fuel oil will escalate at a rate of 16% per year and distillate fuel oil will escalate at a rate of 15.5% per year for the years 1981 and 1982.

72. The EPD method should be used to establish revenue allocation target figures.

73. An adjustment should not be made to the residential allocation target to recognize the burdens of inverted rates and lifeline rates.

74. The adjustment proposed by TURN requires further study in A.60225.

75. Energy charges are much more responsive to usage than demand or customer charges.

76. Energy charges provide better conservation signals than demand or customer charges.

77. The residential gas and electric monthly customer charges should be eliminated.

78. Elimination of the electric residential customer charge results in an inequitable benefit to zero usage residences.

79. A minimum bill of $2.00 per month per electric residential customer will mitigate the inequitable benefits received by zero usage residences.

80. The commercial (G-2) gas customer charge should be eliminated.

81. Rate structure can effect the conservation of energy by consumers.

82. The three-tier residential rate structure contributes significantly to conservation.

83. The present method of defining the second residential tier as double the lifeline quantities has resulted in inequities.

84. A rate structure whereby the residential second tier is defined by an equal amount of usage for everyone is equitable and sends more accurate conservation signals to all customers.

85. A second tier for the residential rate structure, which is defined as 300 kWh for all customers, will result in a more even distribution of extended lifeline customers into all three tiers and is reasonable.

86. Because per capita rates are not administratively practical at this time, the inverted residential rate structure has resulted in some inequities to large households.

87. PG&E should be authorized to establish an experimental TOU schedule which will mitigate the inequities suffered by large households.

88. Marginal capacity costs are derived by energy usage as well as maximum demand.

89. In order to prevent radical changes in rate schedules, all customer and demand charges will not be eliminated at this time.

90. As discussed earlier in the opinion, customer and demand charges will not be increased.

91. The demand ratchet and new customer charge features of the A-12 schedule should be eliminated.

92. The A-21 schedule should be extended as an option to customers below 500 kW.

93. The A-22 and A-23 schedules have similar marginal cost characteristics and should be consolidated as provided in the opinion.

94. Street and outdoor lighting schedules should be increased on a uniform percentage basis.

95. The schedules not subject to specific finding will be determined as provided in Section X of this decision.

96. Short-run marginal costs are appropriate for setting gas rates.

97. The short-run marginal costs are equal to the price of low sulfur #6 or #2 fuel oil.

98. This proceeding is not the proper proceedings to consider changes in lifeline quantities of gas usage.

99. We adopt the guidelines discussed in Section X of the decision, which are just and reasonable.

100. The adopted guidelines are based on marginal costs.

101. The guidelines should be applied sequentially as discussed in this opinion.

102. The attrition allowance for the Gas and Electric Departments should be implemented in accordance with our guidelines.

103. The implementation of the attrition allowance for the Gas and Electric Departments should be made no earlier than January 1, 1983.

104. The adopted rate design and revenue allocations comply with the PURPA rate standards.

105. D.91478 reopened A.58545 and 58546 for the limited purpose of allowing parties to submit evidence and conduct cross-examination with respect to the issue of the most appropriate treatment of PG&E's distribution costs in the formulation of marginal costs.

106. The evidence discussed in Section X supports our treatment of distribution costs adopted in D.91107 in A.58545 and 58546.

Conclusions of Law

1. PG&E should be authorized to file revised electric rates in accordance with this decision which are designed to generate $620.5 million in additional gross revenues based on the adopted test year 1982 results of operations.

2. PG&E should be authorized to file revised gas rates in accordance with this decision which are designed to generate $202.5 million in additional gross revenues based on the adopted test year 1982 results of operations.

3. PG&E should be authorized to file revised electric rates which are designed to generate the additional gross revenues necessary for attrition year 1983 based on our adopted ARA mechanism shown in Appendix E.

4. PG&E should be authorized to file revised gas rates which are designed to generate the additional gross revenues necessary for attrition year 1983 based on our adopted ARA mechanism shown in Appendix E.

5. PG&E should be authorized to revise its AER to $.00276 per KWh to produce $10.7 million in additional AER revenues to recognize the adopted 12.20% rate of return.

6. All other motions or petitions not ruled on previously are deemed denied.

7. The effective date of this order should be the date on which it is signed to meet PG&E's need for immediate rate relief and to meet the requirements of the Regulatory Lag Plan.

INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is authorized to file with this Commission revised tariff schedules for electric rates in accordance with Appendix F to this decision on or after the effective date of this order. The revised tariff schedules shall become effective on the date of filing but not earlier than January 1, 1982, and shall comply with General Order 96-A. The revised schedules shall apply only to service rendered on or after the effective date.

2. PG&E is authorized to file with this Commission revised tariffs to adjust the AER to $.00276 per kWh on or after the effective date of this order. The revised tariff schedules shall become effective on the date of filing but not earlier than January 1, 1982, and shall comply with General Order 96-A. The revised rate schedules shall apply only to service rendered on or after the effective date of this order.

3. PG&E is authorized to file an advice letter requesting additional revenues to offset operational and financial attrition in 1983 for its California jurisdictional electric operations calculated in accordance with our adopted ARA mechanism and is authorized to file revised electric rates reflecting this allowance to become effective January 1, 1983.

4. PG&E is authorized to file an advice letter requesting additional revenues to offset operational and financial attrition in 1983 for its gas operations calculated in accordance with our adopted ARA mechanism and is authorized to file revised gas rates reflecting this allowance to become effective January 1, 1983.

5. PG&E shall resolve the issue of the operating status of Humboldt prior to its next NOI filing for test year 1984.

6. PG&E shall maintain a record of its conservation fund expenditures on a program-by-program basis so that such expenditures may be readily identified, justified, and evaluated for reasonableness.

7. PG&E shall report the status of its conservation funds every six months and submit any unexpended conservation fund balances authorized for 1982-1983 for appropriate rate treatment in the next general rate case.

8. PG&E shall obtain prior approval in writing from the Commission for any redirection of conservation and/or load management funds exceeding $2.5 million in a single year by an advice letter filing.

9. D.91107 with respect to marginal distribution costs is affirmed. A.58545 and 58546 are closed.

10. On or before March 31, 1983, PG&E shall file a report showing for 1982 the dollars budgeted for maintenance, the dollars spent, and the status of maintenance programs.

11. PG&E shall, within 75 days, file a plan to expedite cogeneration in its service area. The plan shall include techniques to overcome the barriers to more rapid implementation of cogeneration.

12. PG&E shall, within 120 days, file a plan for implementation of rate schedule D-7 on an experimental basis for high-use residential customers.

13. PG&E shall file a final report not later than October 1, 1982 on the interruptible rates authorized by Advice Letter 851-E.

14. Workshops shall be held February 4 and 5, 1982, to resolve uncertainties relating to evaluation of conservation performance discussed herein.

15. The record in this proceeding shall be held open on the narrow issue of the reasonableness and feasibility of a procedure for adjusting earnings based on PG&E's conservation achievements.

16. The Executive Director shall serve a copy of this decision on all electric and natural gas utilities in the State. These utilities are invited to file comments on the proposed procedure for adjusting earnings based on conservation achievements. They may also

file alternative proposals. All comments shall be filed with the Commission's Docket Office by February 1, 1982, in the form of prepared testimony. Hearings on all proposals and comments thereon shall commence on Tuesday, February 16, 1982, at 9:30 a.m. in the Commission's Courtroom, 350 McAllister Street, San Francisco, California, 94102.

17. By March 1, 1982, PG&E shall mail to all its customers a bill insert which describes the components of the utility's costs. The complete bill insert to be sent is given in Appendix G of this decision. Its size and form shall be approved by the Executive Director in writing prior to inclusion with any customer's bill.

18. PG&E shall prepare discussion reports and attend a workshop, to be sponsored by the Commission staff, at which the following RD&D issues will be addressed:

(a) The adequacy of PG&E's planning and management of RD&D, and PG&E's response to criticisms thereof in the Cresap, McCormick and Paget management audit, to be detailed as part of the March 1, 1982 filing required of PG&E by D.92940. Copies of the RD&D portion of the March 1 filing shall be provided to prospective workshop attendees, who shall be identified by staff prior to March 1, 1982.

(b) The appropriate definition of RD&D, for accounting and for planning purposes.

(c) The most appropriate mechanism for setting RD&D priorities.

This order is effective today.

Dated December 30, 1981, at San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES
VICTOR CALVO
PRISCILLA C. GREW
Commissioners

The following Commissioners will file concurrences:

/s/ JOHN E. BRYSON
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
Commissioners

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY.

Joseph E. Bodovitz

Joseph E. Bodovitz, Executive Director

SS

APPENDIX A
Page 1

LIST OF APPEARANCES

Applicant: Robert Ohlbach, Daniel E. Gibson, William H. Edwards, and Steven F. Greenwald, Attorneys at Law, for Pacific Gas and Electric Company.

Protestant: Sylvia M. Siegel, Michel Peter Florio, John Blethen, and Arlene Nizenski, Attorneys at Law, for Toward Utility Rate Normalization.

Interested Parties: Rodney Larson, Richard K. Durant, and Susan Magid Beale, Attorneys at Law, for Southern California Edison Company; Dian Grueneich, Gregg Wheatland, Steven M. Cohn, and Arlene Ichien, Attorneys at Law, for California Energy Commission; John L. Mathews and David A. McCormick, Attorney at Law, for the U.S. General Services Administration on behalf of the Federal Executive Agencies; Brobeck, Phleger & Harrison, by Gordon E. Davis, William H. Booth, and James E. Addams, for the California Manufacturers Association; Adrian Arima, Attorney at Law, for Stanford University; William Knecht, Attorney at Law, for the California Association of Utility Shareholders; Glen J. Sullivan and Allen R. Crown, Attorneys at Law, for the California Farm Bureau Federation; William B. Hancock, for Cut Utility Rates Today (CURT); Harry K. Winters, for the University of California; Biddle, Walters & Bukey, by Halina F. Osinski, Attorney at Law, for California Community Colleges; Leonard L. Snaider, Deputy City Attorney, and Robert R. Laughead, P.E., for George P. Agnost, City Attorney, City and County of San Francisco; Cheryl Huete, for Dr. Eugene P. Coyle; Biddle, Walters & Bukey, by Richard L. Hamilton, Attorney at Law, for Western Mobilehome Association; David Weingard, Attorney at Law, and H. W. Carmack, for the City of Oakland; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr, Attorney at Law, for General Motors Corporation; Donald H. Maynor, Attorney at Law, and W. Randy Baldschun, for the City of Palo Alto; McNees, Wallace & Nurick, by Henry R. MacNicholas, Attorney at Law (Pennsylvania), for the California Industrial Energy Consumers; Terry J. R. Kolp, Attorney at Law, for the Department of Defense; Karl E. Vogel, for Energy and Process Systems, Inc.; Bruce Williams, for San Diego Gas & Electric Company; David Roe, Attorney at Law, for the Environmental Defense Fund; David B. Goldstein, for the Natural Resources Defense Council; Howard, Prim, Rice, Nemerovski,

APPENDIX A
Page 2

Canady & Pollack, by Stuart R. Pollack, Attorney at Law, for the Regents of the University of California; Sanford N. Nathan, Attorney at Law, for the International Brotherhood of Electrical Workers, Local Union 1245; Michael Paparian, for the Sierra Club; Robert Gnaizda, Attorney at Law, and Jose Guerrero, for Public Advocates, Inc., Chinese for Affirmative Action, Glide Memorial Methodist Church, Mexican American Political Association, Oakland Citizens Committee for Urban Renewal, League of United Latin American Citizens, Sacramento Urban League, American G.I. Forum, and Officers for Justice; James F. Sorensen, for Friant Water Users Association; Dwight Cocke, for Californians for Nuclear Safeguards; David L. Wilner, for Consumers Lobby Against Monopolies (CLAM); Mary Reiter and Nicholas R. Tibbetts, for the Office of Assemblyman Douglas H. Bosco; Pettit & Martin, by Edward B. Lozowicki and Jack T. Holland, Attorneys at Law, for Owens-Corning Fiberglas; Sam Chapman, Attorney at Law, for Solarcal Local Government Commission on Conservation and Renewable Resources; Johnson, Greve, Clifford & Diepenbrock, by Thomas S. Knox, Attorney at Law, for California Retailers Association; William E. Johns, Attorney at Law, for East Bay Associates; John F. Wilson and Kenneth R. Pepperney, Attorneys at Law, for United States Steel Corporation; and S. V. Radcliff and Michael K. Erickson, for themselves.

Commission Staff: Timothy E. Treacy and Martin A. Mattes, Attorneys at Law, and Bruce M. DeBerry.

(END OF APPENDIX A)

APPENDIX B

PARTIES FILING OPENING OR REPLY BRIEFS

	Opening Brief	Reply Brief
Pacific Gas and Electric Company	X	X
Commission Staff	X	X
California Energy Commission	X	X
Environmental Defense Fund	X	
City of Palo Alto	X	X
Natural Resources Defense Council, Inc.	X	
General Services Administration	X	X
International Brotherhood of Electrical Workers, Local 1245	X	
Toward Utility Rate Normalization	X	X
California Manufacturers Association	X	X
California Association of Utility Shareholders	X	X
California Retailers Association	X	X
California Farm Bureau Federation	X	X
Friant Water Users Association	X	
Western Mobilehome Association	X	
Leland Stanford Junior University	X	
United States Steel Corporation	X	
City and County of San Francisco	X	
Industrial Users	X	
General Motors Corporation		X

(END OF APPENDIX B)

APPENDIX C

PARTIES PARTICIPATING IN ORAL ARGUMENT

Pacific Gas and Electric Company
Commission Staff
California Energy Commission
Toward Utility Rate Normalization
California Association of Utility Shareholders
Industrial Users
General Services Administration
California Farm Bureau Federation
City of Palo Alto
United States Steel Corporation
California Manufacturers Association
Environmental Defense Fund
International Brotherhood of Electrical Workers, Local 1245
City and County of San Francisco
California Retailers Association
City of Coalinga

(END OF APPENDIX C)

APPENDIX D
Page 1

PRELIMINARY STATEMENT (PART B)

ELECTRIC REVENUE ADJUSTMENT MECHANISM (ERAM)

1. Purpose: The purpose of this Electric Revenue Adjustment Mechanism is to adjust revenues for sales fluctuations.

2. Applicability: This ERAM provision applies to all bills for service under all rate schedules and contracts for electric service subject to the jurisdiction of the Public Utilities Commission.1/

3. Base Rates: The Base Rates are the rates for electric service in effect at any time, exclusive of adjustment rates for which a balance or adjustment account is specifically provided in the Preliminary Statement.

4. Base Revenue Amount: The base revenue amount is the annual revenue to be collected from Base Rates. The base revenue amount shall be increased or decreased to incorporate changes in the level of authorized revenue specified in decisions of the Commission with respect to Base Rates concurrently with the beginning of the period to which such revenue applies.

5. Revision Dates: The revision dates are as provided under Part B of the Preliminary Statement (ECAC). On such dates, or as soon thereafter as the Commission may authorize, the utility shall increase or decrease the ERAM rates applicable to each rate schedule and contract in accordance with these provisions.

1/ Except (a) for sales to the California Department of Water Resources under present contracts (b) for sales under experimental Schedules A-20A, A-20B, A-20C, and A-20D.

APPENDIX D
Page 2

6. Electric Revenue Adjustment Account: Beginning as of January 1, 1982, the utility shall maintain an Electric Revenue Adjustment Account. Entries shall be made to this account at the end of each month as follows:

   a. A debit entry equal to, if positive (credit entry, if negative).

      (1) The applicable Base Revenue Amount multiplied by the applicable monthly factor from the table below, less

      (2) The amount of Electric Department revenue from all applicable sales billed during the month at Base Rates.

Month	Monthly Factor
January	8.2%
February	7.8
March	7.8
April	7.8
May	7.9
June	8.8
July	9.1
August	9.2
September	9.0
October	8.2
November	8.0
December	8.2

   b. A credit entry equal to the amount of revenue billed during the month under ERAM rates, if positive (debit entry, if negative).

   c. An entry equal to interest on the average of the balance in this account after entries a. and b. above at the interest rate provided in Part B of this Preliminary Statement.

APPENDIX D
Page 3

7. The ERAM rate shall be equal to the estimated balance in the Electric Revenue Adjustment Account as of the revision date divided by the estimated sales for the four-month period beginning with the revision date. The ERAM rate shall be added to the rates otherwise in effect and shall be separately identified on each rate schedule.

8. Time and Manner of Filing and Related Reports: The utility shall include proposed revised ERAM rates in its ECAC applications. Each such filing shall be accompanied by a report which shows the derivation of the adjustment to be applied.

(END OF APPENDIX D)

ATTRITION RATE ADJUSTMENT (ARA)
MECHANISM WITH INDEXING

1. Purpose: The purpose of this ARA provision with indexing is to set forth a procedure by which an attrition allowance may be established for 1983. The indexing procedure applies only to labor and nonlabor expenses using the given 1982 expenses as a base.

2. Applicability: This mechanism will apply to both the Electric and Gas Departments' attrition allowances for 1983.

3. Filing: On or before October 1, 1982, the utility shall file by advice letter with the Commission the additional revenue requirements necessary to escalate the 1982 labor expenses by a labor escalation rate of 3% plus 74% of the CPI increase between August 31, 1981 and August 31, 1982, and the 1982 nonlabor expenses by the latest DRI forecast for the PPI for industrial commodities applied to the modified PPI developed by the staff.

4. Cost Categories: The cost categories subject to indexing are limited to the changes in labor and nonlabor escalation factors. All other revenue requirement effects of changes in rate base, depreciation expense, income tax, as well as financial attrition, are set forth in paragraph 6.

5. Revenue Requirement Changes: The utility shall compute and report the revenue requirement effects of the attrition allowance calculated as discussed in paragraphs 1-4.

6. The following adopted 1982 labor and nonlabor costs are subject to indexing changes:

APPENDIX E
Page 2

Revenue Requirement
($000)

	CPUC Jurisdictional Electric	Gas
Revenues	Use ERAM	-
Labor[1/] (1982 Base for Indexing)	416,861	211,539
Nonlabor[2/] (1982 Base for Indexing)	231,021	107,164
Fixed Attrition Items		
Depreciation Expense	48,121	13,401
Income Tax Expense	(3,234)	(1,228)
Rate Base	57,429	10,428
Financial Attrition	20,520	6,689

(Red Figure)

1/ Includes Pensions and Benefits and Payroll Taxes.

2/ Excludes Pensions and Benefits, non-ECAC fuel, and property insurance.

7. Rates: Rates will be implemented for the attrition year 1983 according to the discussion in Section X of this decision.

(END OF APPENDIX E)

APPENDIX F
Page 1

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Applicant's electric base rates, charges, and conditions are changed to the extent set forth in this appendix.

Schedule No. D-1	Per Meter Per Month
Rates:	
Customer Charge	Deleted
Energy Charge	
All KWh, per KWh	$ 0.03962
Minimum Charge	$ 2.00

Schedule Nos. DE and DM

No change to present schedules.

Schedule No. DS

Rates:

The effective rate of the single family domestic service schedule, applicable in the territory in which the multi-family accommodation is located, less $1.75 per unit discount.

Schedule No. DT

Rates:

The effective rate of the single family domestic service schedule applicable in the territory in which the multi-family accommodation is located less $4.70 per unit discount.

Schedule No. A-1	Per Meter Per Month
Customer Charge:	$ 1.75
Energy Charge (in addition to the Customer Charge):	0.04317

APPENDIX F
Page 2

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. A-12	Per Meter Per Month
Demand Charge:	
First 40 KW or less of maximum demand	$ 91.00
Next 260 KW of maximum demand, per KW	1.99
Over 300 KW of maximum demand, per KW	1.82
Energy Charge:	
All KWh, per KWh	0.03108

SPECIAL CONDITIONS

Same as present schedule except Special Condition No. 2 is eliminated.

Schedule No. A-15	Per Meter Per Month
Customer Charge	$ 1.75
Energy Charge (in addition to Customer Charge) All kWh, per kWh	0.08325

Schedule No. A-21

Applicability:

After July 1, 1982, this schedule will be optional for polyphase general service customers with a peak demand below 500 KWh.

Rates:	Per Meter Per Month
Customer Charge:	$ 65.00
Demand Charge: Per KW of maximum demand	1.00
Energy Charge: All kWh, per kWh	0.03255

APPENDIX F
Page 3

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedules Nos. A-22 and A-23

The rates on these two schedules are now identical although customer billing information will continue to be maintained separately.

	Per Meter Per Month Period A	Period B
Customer Charge:	$550.00	$550.00
Demand Charge:		
On-Peak, per kW of maximum demand	2.50	.75
Plus Partial Peak, per kW of maximum demand	.30	.25
Plus Off-Peak, per kW of maximum demand	No Charge	No Charge
Energy Charge:		
All kWh, per kWh	0.02934	0.02934

Schedule No. OL-1

	Per Lamp Per Month (Effective Rates)
Mercury Vapor Lamps:*	
175 watts	$13.441
400 watts	21.988
High Pressure Sodium Vapor Lamps:	
70 watts	10.456
100 watts	11.924
200 watts	16.572

* Closed to new installations as of June 8, 1978.

APPENDIX F
Page 4

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. PA-1

Service charge, per customer per month	$2.50
Per hp or kW, per month	0.60
Energy Charge (in addition to Service Charge) All kWh, per kWh	.03134

Schedule No. LS-1

Class			All Night Rates Per Lamp Per Month A	B	C	D	E	F	Half-Hour Adjustment
Nominal Lamp Rating Incandescent Lamps 1/									
Lamp Watts		Lumens							
58		600	5.599						.154
92		1,000	6.652						.318
189		2,500	11.059	9.508					.497
295		4,000	14.629	13.076					.683
405		6,000	18.396	16.840					1.043
620		10,000	26.192	24.681					
Mercury Vapor Lamps 2/									
Lamp Watts	Line Watts	Lumens							
100	124	3,500	9.589	8.467	7.086	14.844	14.114	11.620	.184
175	198	7,500	11.825	10.743	9.728	16.742	16.410	13.902	.295
250	185	11,000	14.735	13.614	12.612	21.150	19.415	17.728	.423
400	451	21,000	20.783	19.403	18.140	-	25.765	23.424	.672
700	766	37,000	33.828	30.899	-	-	38.444	37.865	1.143
1,000	1,088	57,000	44.566	41.464	-	-	49.660	48.535	1.623

1/ Service for incandescent lamps is limited to those installations in service as of September 21, 1975.

2/ Closed to new installations.

Note: Rates shown are the effective rates.
Included are: AER at $.00276 per kWhr, SFA at $.00002 per kWhr, CFA at $.00018 per kWhr, ECAC at $.05406 per kWhr

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. LS-1 (Cont'd.)

Class			All Night Rates Per Lamp Per Month						Half-Hour
			A	B	C	D	E	F	Adjustment
High Pressure Sodium Vapor Lamps									
Lamp Watts	Line Watts	Average Initial Lumens							
70	85	5,800	10.457	9.315	7.947	14.790	14.410	11.977	.116
100	121	9,500	11.934	10.787	8.856	15.887	15.576	13.447	.164
150	176	16,000	13.654	12.519	10.769	17.535	17.612	15.178	.240
200	263	22,000	16.571	15.429	13.681	-	20.677	19.991	.361
250	321	25,500	18.570	17.448	15.776	-	22.771	22.085	.441
400	487	46,000	24.016	22.868	21.121	-	28.114	27.430	.669

APPENDIX F
Page 6

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. LS-2

Operating Schedule -- Nominal Lamp Rating: Incandescent Lamps			Utility supplies energy and switching* servies only. All Night	Utility supplies the energy, switching* and maintenance service for lamps and glassware. All Night	Utility supplies the energy, switching* and maintenance service for entire system including lamps and glassware. All Night	A,B and C Half-Hour Adjustment
Watts	Lumens**					
92	1,000		3.390	4.454	5.458	.154
189	2,500		7.005	8.297	9.300	.318
295	4,000		10.931	12.299	13.304	.497
405	6,000		15.026	16.394	17.397	.683
620	10,000		22.939	24.491	25.475	1.043
860	15,000		31.825	33.558		1.447
Low Pressure Sodium Vapor Lamps						
Lamp Watts	Line Watts	Average Initial Lumens				
35	60	4,800	2.051	-	-	-
55	90	8,000	2.728	-	-	-
90	148	13,500	4.485	-	-	-
135	205	21,500	6.190	-	-	-
180	255	33,000	7.686	-	-	-
High Pressure Sodium Vapor Lamps						
	120 Volts					
Lamp Watts	Line Watts	Average Initial Lumens				
70	85	5,800	2.549	3.664	4.449	.116
100	121	9,500	3.609	4.506	5.511	.164
150	176	16,000	5.280	6.177	7.180	.240
	240 Volts					
Lamp Watts	Line Watts	Average Initial Lumens				
70	98	5,800	2.993	3.889	4.895	.136
100	144	9,500	4.342	5.239	6.243	.198
150	205	16,000	6.190	7.087	8.090	.281
200	263	22,000	7.948	8.891	9.895	.361
250	321	25,500	9.707	10.649	11.653	.441
400	487	46,000	14.720	15.664	16.667	.669
Metal Halide Lamps**						
Lamp Watts	Line Watts	Average Initial Lumens				
400	468	30,000	14.136	-	-	.642
1,000	1,118	90,000	33.727	-	-	1.533
Mercury Vapor Lamps**						
Lamp Watts	Line Watts	Average Initial Lumens				
100	124	3,500	4.053	4.781	5.786	.184
175	198	7,500	6.500	7.239	8.232	.295
250	285	11,000	9.308	10.235	11.239	.423
400	451	21,000	14.793	15.722	16.725	.672
700	766	37,000	25.154	26.901	27.890	1.143
1,000	1,088	57,000	35.707	37.546	38.551	1.623

* Switching Service is closed to new installations.
** Closed to new installations.

Note: Rates shown are the effective rates
Included are AER at $.00376 per KWHR
CFA at $.00018 per KWHR
SFA at $.00002 per KWHR
ECAC at $.05406 per KWHR

APPENDIX F
Page 7

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. LS-3 (Cont'd.)

	Per Meter Per Month
Service Charge:	$3.00
Energy Charge (in addition to Service Charge)	
All kWh, per kWh	0.04235

Schedule No. TC-1

Service Charge:	
For each service connection	$1.75
Energy Charge (in addition to Service Charge)	
All kWh, per kWh	0.04317

Special Contract - BART

Demand Charge:	
Per kW of billing demand	$2.15
Energy Charge:	
Per kWh	0.02240

APPENDIX F
Page 8

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

<u>Schedule No. PA-2X</u>

	Per Meter Per Month	
Monthly Service Charge:	$2.50 plus $1.30 per kW of On-Peak Maximum Demand	
Energy Charge (In Addition to the Service Charge)		
	Period A	Period B
On Peak, per kWh	$0.04821	$0.04113
Plus Partial Peak, per kWh	0.02813	0.02813
Plus Off-Peak, per kWh	0.02412	0.02412

END OF APPENDIX F

APPENDIX G

Bill Insert for PG&E Customers

Where Your Current Utility Dollar Goes

Electricity		Gas	
Fuel	62¢	Fuel	81¢
Non-labor Expenses	15¢	Non-labor Expenses	8¢
Labor	8¢	Labor	5¢
Profits	6¢	Profits	2¢
Other Taxes	6¢	Other Taxes	3¢
1981 Tax Act*	3¢	1981 Tax Act*	1¢

The above charts indicate the size of the various utility cost categories that are a part of your bill.

* Note that this is a new cost item which constituted 21% of PG&E's 1982 general rate increase, costing ratepayers an additional $177.4 million dollars. This item results from President Reagan's Economic Recovery Tax Act of 1981, which requires the CPUC to charge ratepayers for the expense of taxes which are not now being paid to the Federal Government and which may never be paid. This expense will increase in the future as a percent of your bill.

GLOSSARY
Page 1

A.	Application
AA	Annual Adjustment
AAA	Average Annual Adjustment
ACRS	Accelerated cost recovery system
ADL	A. D. Little
AER	Annual Energy Rate
AFUDC	Allowance for funds used during construction
AGA	American Gas Association
ALJ	Administrative Law Judge
ARA	Attrition rate adjustment
A&G	Administrative and general
A&S	Alberta and Southern Gas Producers Association
BLS	Bureau of Labor Statistics
CAUS	California Association of Utility Shareholders
CFA	Conservation Financing Account
C-I-A	Commercial-Industrial-Agricultural
City	City and County of San Francisco
CMA	California Manufacturers Association
CMP	Cresap, McCormick and Paget
CPI	Consumer Price Index
CPI-W	Consumer Price Index for Urban Workers
CPUC	California Public Utilities Commission
CRA	California Retailers Association
CVR	Conservation voltage regulation
CWIP	Construction work in progress
D.	Decision
DCF	Discounted cash flow
Diablo	Diablo Canyon Plant
DOE	Department of Energy
DRI	Data Resources, Incorporated
DWR	Department of Water Resources
ECAC	Energy cost adjustment clause
ECB	Energy Conservation Branch
ECH	Energy conservation home

G L O S S A R Y

EDF	Environmental Defense Fund
EEDA	Energy exploration and development adjustment
EEO	Equal opportunity employment
El Paso	El Paso Natural Gas Company
Energy Commission	California Energy Commission
EPD	Equal percentage of the differences
EPRI	Electric Power Research Institute
ERAM	Electric revenue adjustment mechanism
EUA	Energy utilization audit
Farm Bureau	California Farm Bureau Federation
FCA	Fuel cost adjustment
FERC	Federal Energy Regulatory Commission
GAC	Gas adjustment clause
GEDA	Gas exploration and development adjustment
GM	General Motors Corporation
GNP	Gross National Product
GRI	Gas Research Institute
GSA	General Services Administration
Humboldt	Humboldt Nuclear Power Plant
Industrial Users	General Motors Corporation, Kaiser Steel Corporation, Monsanto Company, and Union Carbide Corporation
ITC	Investment tax credit
LMS	Load management standards
MW	Megawatt
NEAR	Nonearning assets ratio
NOI	Notice of Intention
NRC	Nuclear Regulatory Commission
NRDC	Natural Resources Defense Council, Inc.
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
PG&E	Pacific Gas and Electric Company
PGT	Pacific Gas Transmission Company

G L O S S A R Y
Page 3

PHFU	Plant held for future use
PPI	Producers Price Index
PU Code	Public Utilities Code
PURPA	Public Utility Regulatory Policies Act of 1978
RCS	Residential conservation services
RD&D	Research development and demonstration
R&E	Research and experimentation
RPA	Resource Planning Associates
SAM	Supply adjustment mechanism
SFA	Solar Financing Account
SoCal Edison	Southern California Edison Company
SoCal Gas	Southern California Gas Company
SRMC	Short-run marginal cost
Staff	Commission staff
Stanford	Leland Stanford Junior University
STAR	Solar technology assessment and referral
Tax Act	Economic Recovery Tax Act of 1981
TOU	Time of use
TURN	Toward Utility Rate Normalization
U.S. Steel	United States Steel Corporation
WPI	Wholesale Price Index
ZIP	Zero interest program

D.93887
A.60153 et al.

COMMISSIONER JOHN E. BRYSON, Concurring:

I concur.

This has been an unusually difficult decision because it comes at a time of intense distress both for the ratepayers -- who are already facing historically high gas and electric rates -- and for the utility, which -- despite the higher rates of recent years -- has been in an eroding financial position.

Predictably, when the interests of affected parties are as widely divergent as they are here, this decision will be a tough one for all to accept. The decision makes sharp cuts in nearly all areas of PG&E's requests. PG&E will have to make wrenching management and cost control decisions to live within it. Despite these sharp cuts, the decision authorizes another significant increase for residential and business consumers who are already hard hit by utility bill increases and the general stresses of combined inflation and recession.

A question which deserves comment is whether the future promises only more of the same -- higher rate increases from a utility in a continually deteriorating financial position. The answer must be a mixed one in the short term, but there is, I believe, real prospect for improvement. The causes of current distress have been inflation, a heavy dependence on oil and natural gas, and the massive investment of utilities in large long lead-time construction projects.

Inflation is a problem in all areas of the economy, but a particularly difficult one in the regulated sector where there has always been a lag between cost incurrence and rate adjustment. Through our regulatory lag plan and attrition adjustment, the Commission is dealing more effectively with inflation, but there is no way to fully protect the ratepayer from its effects.

Due to our geographical position on the coast with indigenous oil and natural gas resources but remote from coal, California utilities built oil and natural gas power plants through the 1960's. Those were sound decisions based on all facts known and foreseen at the time, but they have left us as a state vulnerable to the extraordinary price increases and volatility in oil and natural costs in recent years. Thus, fuel costs made up only 16% of the typical PG&E electric bill in 1970 and are 62% of that cost today.

Finally, PG&E, along with nearly every other utility, set out in the late 1960's and early 1970's to build a new generation of larger more technically complex power plants, generally nuclear plants. At a time of stable prices and a history of success in bringing construction projects to a timely conclusion and increasing economies of scale stemming from technological improvement, these appeared to be sound decisions. But, in fact, these massive construction commitments have crippled the utilities and thus indirectly hurt the consumer. Complex technology coupled with the immense size of these projects and deep social concern about their health and environmental impacts have stretched out the construction period far beyond that projected, and this has occurred at the same time that the costs of financing new construction have tripled and quadrupled. And since the investor-owned utilities have under traditional utility regulation borne all of the costs of construction and associated financing until a plant is in operation, they have had to bear this immense financial burden.

What can be done to cope with inflation, oil and gas dependence and power plant construction costs in the future? While the consumers and the utility have divergent short-term interests in the level of utility rates, there ia a common interest in an adjustment to these persistent conditions which will moderate future rate increases and ensure the reliable provision of supplies.

That adjustment lies in my judgment in sharply increased efficiency in the use of our energy supplies and in the development of more diverse and smaller scale shorter-lead time supply sources. This approach alone appears to have the promise of minimizing the vulnerability of our supply system to uncontrollable oil and natural gas prices and the ravages of high construction and financing costs on large complex power plant projects.

Two parties in this case, PG&E and the California Energy Commission, proposed sharp changes from traditional ratemaking policy as means of getting to a future supply base less vulnerable to current problems. Neither approach was adopted, but both deserve comment.

PG&E proposed three accounting adjustments to improve cash flow. PG&E argues that this would allow the utility to return to full financial health and appropriate energy development would then follow.

While improving the utility's financial health is important to encourage development of new resources, PG&E's proposed cure presents its own problems. As our staff pointed out in this case, PG&E's current cash flow difficulties stem largely from the fact that the Diablo Canyon and Helms power plant projects have not entered the rate base. The utility asks the Commission to adopt measures that place much of the cost of plants under construction on current ratepayers, shielding the utility from risk. While adopting such ratemaking treatment might encourage development of new resources, it would remove an incentive for the utility to choose carefully among competing technologies and to construct plants in an efficient and timely manner.

Rather than adopting risk shielding measures to improve the financial health of utilities, I would prefer to authorize appropriate returns on equity and place the risks of development on the utility. Given the magnitude of utility investments, it is essential that incentives exist for efficient development of resources.

The Energy Commission, for its part, presented a ratemaking proposal to encourage utility development and promotions of new small scale resources. The Energy Commission suggests that we authorize a three percentage point higher return on equity and shorter depreciation lives for renewable resource investments by utilities. Insofar as this proposal would authorize a return on investment to reflect risks assumed rather than simply shifting investment risks onto ratepayers, it is more consistent with my thinking. However, given the great advantage of renewables in terms of lower costs, smaller size, and shorter construction lead times, utilities should prefer such sources over large base load plants such as coal and nuclear even absent the Energy Commission's proposal. It therefore is important to analyze carefully whether an additional incentive is necessary.

The utilities are not the only source of new electric generating capacity to reduce oil use. Likewise, important are the conservation efforts of individual customers and the development of capacity from unregulated third parties. As the Commission has emphasized in the past, we place highest priority on the development of such resources. PG&E's efforts to promote conservation and third party generation have improved in recent years, partly no doubt due to our prodding, but also because it has become in the company's interest to do so. As PG&E itself has pointed out, conservation and third party development reduce the company's need to build new facilities. Under current conditions, reducing financing requirements is to the benefit of shareholders.

The Energy Commission further argues that we should provide an additional rate of return reward for utility achievements at purchasing electricity from third parties. Rather than being simply a non-profit, cost-recovery activity, wholesale energy purchasing would become of real value to the utility shareholders. The question is whether such a reward, which would raise the cost to the ratepayer of such outside supply sources above the utility's estimated cost for its own supply projects, would provide long-term benefits by accelerating the introduction of such supplies into the utility system.

Despite our decison not to adopt in this decision the more dramatic breaks with traditional ratemaking proposed, I believe further analysis of the impacts of our rate decisions and methodologies on utility supply planning is needed. I am troubled, for example, by the incentives that our fuel adjustment clauses appear to create for continued reliance on oil and gas. The Energy Commission deserves credit for proposing new ideas in the form of reward-penalty mechanisms that would provide additional incentive for utility promotion of new diverse supply sources. Our objective must be to provide the minimum adequate incentive and financial capacity for such change. Excessive or poorly designed rewards could have the perverse effect of making inherently economical approaches overly costly to consumers. The reward-penalty mechanism proposed in this case today for utility conservation efforts in an important step toward further analysis of such an approach.

In any event, today's decision provides -- in an atmosphere of great fiscal constraint -- vital building blocks toward the needed adjustment in our energy supply base. By adopting the ERAM sales adjustment mechanism, the Commission removes the disincentive to utility conservation efforts inherent in traditional ratemaking. By not authorizing PG&E's cash flow proposals, the Commission declines to shield the utility further from market forces, and thereby retains the full incentive for rigorous management decision making responsive to changing economic conditions. By updating the rate of return and adopting the attrition allowance, the Commission provides PG&E the basis -- with aggressive cost control -- for necessary new investment. And by providing for steadily expanded conservation and load management efforts, the Commission maintains the drive toward increased efficiency.

December 30, 1981
San Francisco, California

JOHN E. BRYSON, President

RICHARD D. GRAVELLE, Commissioner, Concurring:

I concur. I write separately to discuss two matters of particular concern.

The first matter concerns the consequences for our rate-making process of living in an era of sky high utility bills. The second concerns a new approach to the problem of revenue allocation in electric rate design.

It is commonplace to observe that energy rates are high and going higher. The ordinary citizen's first reaction is, of course, to ask why the Commission does not keep rates down, as if applications for rate increases could be denied regardless of inflation, higher costs of materials and supplies, escalating fuel bills and increased labor expense. Years ago, every extra unit of electricity or gas sold actually lowered the cost for everyone. Greater consumption led to greater economies of scale, leading to even cheaper rates. Perhaps the ordinary citizen still remembers those halcyon days. Now we see the exact opposite. Every extra unit of electricity or gas sold increases the cost for every customer on the system. The cost of generating one new unit of electricity or distributing one more unit of gas - commonly referred to as marginal cost -- keeps rising as the cost of primary fuels, oil and natural gas, keep rising. This situation has been noted many times and I will not dwell on it. But I would like to point out what it means for the regulatory process.

I return to the ordinary citizen's question, "Why doesn't the Commission keep rates down?" What I think the public increasingly demands is that the Commission go over every account on PG&E's books and weed out every single penny that is unnecessary or wasteful.

In the past, it was sufficient for our staff to make estimates of future expense levels based on trending or similar analyses. It was assumed that increasing efficiencies of scale and increased efficiency due to higher labor productivity would produce sufficient savings to allow the utility to meet any unforeseen expense. In those days a regulatory commission's chief concern was to insure that the utility did not earn beyond its authorized return. Now, however, despite generous regulatory assistance, costs are increasing at such a rate that it is rare for a utility to earn its authorized return. The result has been two-fold: first, utilities have begun to embrace the concept of living within their "authorized" expense levels, and second, the ratemaking process has become one of establishing a "budget" for utilities consisting of various "authorized" expense levels for different utility activities, such as maintenance, overhauling, building new facilities and the like. Increasingly our task is not simply to trend expenses to general levels, as we used to do in the past, but to examine claims that this or that activity is proper and that the activity must be funded at such and such an amount. We are asked, in short, not to determine general expense levels but the propriety of individual expenditures and projects. For example, during oral argument great attention was focused on whether PG&E should do one or two gas turbine overhauls in 1982 and on how many new hires it should add for steam maintenance operations.

It would be nice to think we have an infallible ability to make such decisions. In any given instance our staff can examine such questions and bring us a recommendation in which we can and do have great confidence. But it is important to remember that we are dealing, in the case of PG&E, with a rate increase application of over a billion dollars. No one individual, and certainly not just five commissioners, could ever hope to examine every single account involved in a ratemaking case so large. The fact is that not even our staff, large and skilled as it is, has the time or resources to examine every account down to the last dollar, to decide whether x dollars for tree trimming would suffice instead of y, whether z number of employees for line maintenance would suffice instead of any other number. To its credit, TURN in this case has applauded the efforts of our staff, and I would like to add a word of praise myself. The time and energy put into this case by our staff has been nothing short of phenomenal. Yet still, for almost any given account, one would be hard pressed to say with absolute certainty that he had not given too much or too little. Reduced to one sentence: ratemaking is not an exact science. It depends on input from engineers, accountants, economists, lawyers, company witnesses, staff witnesses, special interest witnesses, consumer witnesses, all with a different perspective on what MUST be done. To expect precision from such a process is absurd.

Yet increasingly the public demands that not one penny more than what is absolutely necessary be granted to any energy utility. In an era of sky high utility bills, it is only natural that this demand be repeated incessantly. Increasingly this demand will become the mainspring of our regulatory process. It is inevitable.

At first blush it may appear desirable. But the consequence is that increasingly this Commission will be thrust into the role of managing the utility, of making day to day, or perhaps month to month, decisions as to what work should and should not be done, at what expense. Wisely, today we resist that temptation in PG&E's conservation program, according the utility broad latitude to reallocate its funds as it sees fit for accomplishment of the greatest savings. But not so happily we today direct PG&E to file maintenance expenditure reports. We have to do this in the context of today's decision, to determine whether PG&E will actually spend the dollars it says it needs on maintenance programs. But this may be a long step toward managing the utility, which is to enter a game we can only lose.

Our only hope for dealing with this situation is to demand that the utilities themselves now adopt a rigorous budgeting process, something which, unbelievably, PG&E is still months away from having in place. We have to demand as well that once the budget is determined by the utility and "authorized" by this Commission, the utility must live within its overall budget, reallocating as necessary within that total and not coming back to this Commission because certain expenses have exceeded those originally anticipated. Utilities have to understand that authorized returns will be earned only by those utilities whose managements keep expenses within their budget. Only in this manner can utility incentives be preserved and only in this manner can we avoid the spectre of this Commission establishing a utility's operations.

In the area of rate design, I feel that we do not have an adequate methodology for guiding our decisions on revenue allocation between customer classes. In this decision we draw upon the "equal percentage of the difference" (EPD) rule for revenue allocation in the electric department. While this rule provides a pausible method for allowing class by class revenue requirements to move toward marginal cost levels, it does not provide much insight in the face of the expected continuing divergence between marginal costs and rates. Further, despite this Commission's oft stated support for marginal cost principles, the equal percentage of the difference rule gauges class by class rate increases according to existing base rates which are founded largely on embedded costs.

We need to develop a more explicit revenue allocation methodology which is grounded more fully on marginal cost principles. In future proceedings, I hope that the staff and other parties will consider the following possible approach to revenue allocation: as a starting point, a revenue requirement for each customer class should be derived which indicates the revenues that such a class would generate if it paid rates according to the time differentiated short run marginal cost that the class causes the system to incur.

This marginal cost would cover marginal energy costs and all appropriate shortage costs. To keep utility profits at reasonable levels, actual rates of course would need to diverge from, i.e., be set lower than, marginal cost level rates. A second step would thus be to allocate the necessary divergence between actual revenues and marginal cost level revenues for each class. This should be done according to two principles: equity and efficiency. The efficiency principle will require that the rate charged a particular customer class will diverge from marginal cost levels in inverse proportion to price elasticity of demand that the group of customers exhibits. This promotes efficiency because it maintains replacement cost price signals most strongly for the most price responsive "elastic" users, thus minimizing any energy use distortions arising from the marginal cost-rate divergence. The equity principle, on the other hand, will require that all customer group rates diverge from marginal cost levels by an equal amount. This would lead to each customer class paying an equal percentage of their respective marginal cost rate levels. The interplay of these two principles establishes a range of possible total rate levels based on marginal costs.

Had such a target range been developed in this proceeding, it is quite possible that it would have provided substantial support for the argument that the rate increase should have been shouldered more by large users and less by lifeline residential users. This is because the former group is generally thought to have more elastic demand patterns than the latter.

In my view, there are two other reasons why revenue requirements should be shifted from the residential classes to the commercial and industrial classes. The EPD mechanism tends over the long haul to cause the residential class alone to bear the burden of lifeline, thereby undermining our initial assignment of that burden to all customer classes. A revenue shift is also supported by the fact that larger commercial and industrial users do not face inverted rate structures as residential users do; the former see flat rates for all consumption within any given time period, rates which are far below marginal cost. A revenue shift remedies both problems. The major problem, however, is that the proper size for such a shift has not been identified. In this situation, a ten percent shift of revenues from the residential class to the light and power, agricultural and railway classes might be reasonable. We cannot know this on the present record, however. The new revenue allocation method suggested above would help us know how much of a shift is in order.

Some might argue that the use of this new approach to revenue allocation would be too difficult because it relies on marginal costs and elasticity numbers. But we are already employing forecasting to small power pricing - and they are certainly no more troublesome than the cost allocation study numbers that we have historically utilized.

Richard D. Gravelle, Commissioner

San Francisco, California
December 30, 1981

A.60153 et al., D.93887

COMMISSIONER LEONARD M. GRIMES JR., Concurring:

I concur with the decisions being made in this order, but will make several comments in hopes of giving some clear insight into my personal feeling about a few issues.

The first of these is that the major issue in the case was the size of the request--I believe the first request over $1 billion in the nation. In fact, if the company's perceived needs had not loomed so large, maybe more progress could have been made toward finding better regulatory techniques and concepts for our mutual future well being.

This situation is further strained by the highly publicized problems being experienced at the Helms pumped storage project and Diablo Canyon. Neither of these projects is directly a part of this general rate request, but one cannot deny they have poisoned the well in the minds of the public. The need to resolve the problems brought by Diablo and Helms has never been greater. Carrying the ever increasing cost of these projects is not only a major financial strain on PG&E and its stockholders, but a constant threat to our ratepayers. This is not the day we must face judgment on the prudence of PG&E's expenditures on these projects, but the sooner that review can take place, the better off we all will be.

In face of all of this and much more, including the passage of the Reagan 1981 Tax Act at the end of our schedule, the mass meetings of consumers, middle of the night phone calls, and thousands of letters, I feel that the Commission has maintained its equilibrium and has made a good decision. I, for one, find no difficulty in supporting the 16 percent return on equity granted and note that we, <u>in California</u>, are working as hard as any Commission to support the need to provide <u>opportunity for stability</u> of our electric utility industry. In recent months, 17 plus other state commission decisions around the country provided a

16 percent plus ROE (but none approached the 18 percent requested in this case. Even with the prime pointing down, with utility debt commanding interest rates of 15 percent to 17 percent, our decision reflects current financial reality. I am content to let the Tax Act windfall and the introduction of ERAM substitute for the extraordinary cash flow request denied by this decision.

Except for the continued support of lifeline (a statute requirement in this state) and our special efforts to insure that some benefit from our conservation expenditures (ZIP, solar, et al) result, this decision will not satisfy the low income groups that worked hard to block any increase. Supplying electricity and gas is a business with a commodity to sell at a stated price. The system and the laws governing our behaviour makes no provision for those who cannot pay that price. I can only continue to make sure that no one has to pay more than necessary--rich man, poor man! The companies that we regulate must also work harder to provide affordable energy to the people of our state and nation.

In signing this order, I wish to point out that my opposition to the granting of a discount on gas and electric bills to utility employees has not been altered by postponing action leading to such elimination. I am not at all persuaded by the union out cry--when all over this nation, managements and unions are reassessing their agreements to keep plants from closing and jobs from being lost-- that we, at this Commission, are without jurisdiction to even comment on this arrangement. My principal objection is that the public is paying for the discounts. The threat that the union will make extraordinary wage demands on the company and this Commission if they lose this discount does not deter me in the least. If at the bargaining table the union can convince management that they are worth more--hopefully through a demonstration of improved productivity--I think that is good and proper, supportable and better than some obscure, under-the-table, free deal, on utility bills.

The primary exception to the status quo relates to the effort of the Energy Commission to introduce the old idea of management incentives relative to our need for promoting conservation and the use of alternative source of electrical generation. I believe the basic concept is right and have personally proposed a program for extending this concept of regulation. I only wish that our process would have allowed the matter to have been worked out in this case. We have, however, started the ball rolling by proposing that incentives (reward and penalty) for conservation performance be worked out for PG&E by extending our hearings to developed the details--I hope the concept is beyond debate.

As I stated in my Proposal of October 1, we must all reevaluate the allocation of risk between ratepayers and shareholders and the consequent opportunities available to the utility for the risk it assumes. Incentives are an important regulatory tool to convey the risks and rewards of the market place to utility management. We are approaching closure on incentives for conservation. We are well down the road in evaluating incentives for resource investments and operating efficiency. The ratepayers, the utilities, and the regulatory process will all benefit if we give serious attention to incentive mechanisms and work constructively to resolve apparent problems.

LEONARD M. GRIMES, JR., Commissioner

San Francisco, California
December 30, 1981

A. 60153 D.93887

COMMISSIONER VICTOR CALVO, CONCURRING:

By my concurrence, I simply wish to emphasize that I expect a careful and thorough analysis of both the appropriateness of conservation incentives for utilities and the viability of each incentive proposal offered at hearing. The purpose of a continued hearing is to develop a complete record, not only on the threshold policy of whether conservation incentives are appropriate but also on the various forms an incentive proposal may take. The proposal outlined in the decision is one possible approach but by no means should be considered the only, or even the favored, approach. I strongly urge our staff and all interested parties to comment on the outlined proposal and to offer alternate proposals if appropriate.

Dated, December 30, 1981 at San Francisco, California.

Victor Calvo

VICTOR CALVO, COMMISSIONER