ALJ/rr/jt

Decision 83 12 068 December 22, 1983

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 82-12-48 (Filed December 20, 1982)

(For appearances see Appendix C.)

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O P I N I O N

I. SUMMARY OF DECISION

This decision authorizes Pacific Gas and Electric Company to increase electric rates by $219,934,000 and gas rates by $78,787,000 for test year 1984. The authorized electric revenue increase reflects reductions of $43.4 million due to an ERAM overcollection in 1983, and $22.9 million due to unspent conservation and load management funds in 1983, and an ECAC/AER reduction of $8,815,000.

PG&E had originally requested an electric base revenue increase of $787,578,000, and a gas base revenue increase of $206,894,000. PG&E revised its request twice more to arrive at a final electric revenue increase of $630,353,800 and a gas revenue increase of $146,107,000. Its final request, net of the ERAM adjustment discussed above, is $93,798,000 for the Electric Department, and $146,107,000 for the Gas Department.

The adopted electric and gas revenue requirements represents a 5.9% and 1.95% increase, respectively, over current revenues at present rates.

PG&E is authorized to file for an attrition allowance in 1985 in accordance with the attrition rate adjustment mechanism set forth in this decision.

A typical residential customer electric bill for 500 kWh will increase from $29.92 to $31.94. For the residential gas customer using 106 therms, the typical increase will be from $47.02 to $48.86.

The decision provides PG&E an opportunity to earn a 15.75% return on equity in 1984. PG&E had requested a return on equity of 17.5%.

Several features deserve special attention. First, in the area of Operation and Maintenance expense the decision authorizes PG&E about 95.5% of its request. This presents about a 20% increase over the amount authorized in PG&E's last general rate decision. In addition, the decision authorizes $10 million in unforeseen maintenance expense and $4.8 million each year to fund PG&E's Reliability Improvement Program in the next two years. The latter amount represents half of PG&E's request. The decision recognizes that the program is worthwhile but concludes that PG&E has not demonstrated that it can, as a practical matter, efficiently and cost-effectively spend the requested amount in the next two years.

Also, the decision denies PG&E's request of $10.6 million in deferred maintenance. This treatment is consistent with the decision in Southern California Edison's last general rate case.

Second, the decision apportions the direct costs of the feasibility studies for abandoned projects to ratepayers, amortized over four years. PG&E's shareholders are required to absorb all AFUDC costs on these projects. PG&E's proposal to recover abandoned project costs on an estimated basis is rejected.

Third, the decision allocates both the gains and losses from the remaining Montezuma investment which had not previously been disposed of to PG&E's shareholders. This treatment is comparable to that given to the portion of the investment in rate base.

Fourth, the decision authorizes $54 million for conservation and $28 million for load management. The decision adopts a policy guideline of "holding the line" on 1984-1985 expenditures to levels previously authorized and recorded in 1982 and 1983. PG&E is given discretion to allocate up to $2.5 million among individual programs. Amounts which are not spent in 1984 will accrue interest and be applied to 1985 expenditures. As previously mentioned, the unspent conservation and load management expenditures remaining from 1983 have been used to offset the 1984 electric revenue requirement.

Fifth, the decision does not allow PG&E to recover past incurred franchise fees owed to the City of San Jose. To allow recovery would be contrary to test year ratemaking principles.

In the area of residential rate design, the decision adopts electric and gas baseline allowances which will be implemented by May 16, 1984. The electric baseline allowance is set at 80% of the system average rate. The gas baseline allowance is set at 85% of the system average rate.

The decision retains the three tier residential rate structure and eliminates customer charges in favor of a minimum bill. For commercial, industrial and agricultural customers on TOU rates, the rates are structured to create summer and winter differentials during on, mid and off-peak periods. Meter charges are also established.

II. INTRODUCTION

A. Procedural Summary

This proceeding was assigned to Commissioner Victor Calvo and Administrative Law Judges (ALJ) Bertram Patrick and Kenneth K. Henderson. ALJ Patrick presided over results of operations and ALJ Henderson presided over the rate design, load management and conservation phases.

On September 14, 1982, pursuant to the Commission's Rate Case Plan, PG&E filed its Notice of Intention (NOI) to file a combined gas and electric general rate application based on a 1984 Test Year. This NOI, with accompanying exhibits and testimony, was accepted for filing by the Commission on October 21, 1982.

On December 20, 1982, PG&E filed A.82-12-48 requesting authorization to increase its electric and gas base rates effective January 1, 1984. The rates proposed by PG&E were designed to produce gross revenue increases over the base rates expected to be in effect on January 1, 1983, for the Electric Department, CPUC Jurisdictional, of \$787,578,000, for the Gas Department of \$206,894,000, and for the combined Departments of \$994,472,000. In percentages, these increases over rates in effect on December 12, 1982, were 20.4%, 6.1%, and 13.7%, respectively.

On March 21, 1983, because inflation had diminished, PG&E reduced its request to \$634,382,000 for Electric and \$166,043,000 for Gas, or \$800,425,000 for the combined Departments. Numerous minor adjustments were made throughout the hearing process. At the close of the updating hearings on September 21, the final PG&E request was \$630,353,800 for Electric and \$146,107,000 for Gas, or \$776,460,000 for the combined Departments.

This increase will be somewhat offset by two factors. First, sales will increase ~~in 1984~~ over the previously adopted sales thereby producing additional revenues. Second, PG&E's base rates have been increased to amortize an ERAM undercollection which would also produce additional revenues at present rates. Therefore, the net increase in customer rates requested by PG&E is $493,798,000 for Electric, and $146,107,000 for Gas, or $639,905,000 for the combined Departments as reflected in the Updated Comparison Exhibits 258 and 259.

A prehearing conference was held on January 28, 1983, in San Francisco. Public witness hearings were held in afternoon and evening sessions in Placerville, Red Bluff, Eureka, Oakland, San Francisco, Santa Cruz, and Fresno on May 9, 11, and 12, and June 6, 7, 8, and 9, 1983, respectively. These sessions were scheduled especially for the purpose of receiving testimony and statements directly from members of the public. A total of 90 members of the public presented testimony; nearly all protested the magnitude of the proposed rate increase. None complained about the quality of service they were receiving. All told, approximately 300 customers attended these sessions. Aside from the public witnesses that testified, the Commission also received over 1,250 letters from customers, as well as resolutions and statements expressing their concerns.

On March 18, the staff presented testimony in support of its motion concerning the accrual of Allowance for Funds Used During Construction at Humboldt Unit No. 3. On March 21, 1983, PG&E began its direct presentation at hearings in San Francisco. During 72 days of evidentiary hearings, witnesses representing PG&E, the Commission staff, and numerous interested parties presented testimony and sponsored 241 exhibits. Evidentiary hearings were completed and the application was submitted for briefing on July 22, 1983. Concurrent opening briefs were filed on August 22, 1983, and concurrent closing briefs on September 13, 1983.

The updating hearings, specified under Day 265, 275, and 280 of the Rate Case Plan were held September 19-21, 1983. During these 3 days of additional evidentiary hearings, 18 new exhibits were sponsored. On September 22 oral argument was held on all updating issues in lieu of written briefs except the issue of franchise fees. Briefs were filed September 30, 1983. These hearings also included a presentation on the issues surrounding PG&E's proposed Underground PCB Transformer Replacement Program.

Oral argument before the Commission en banc was held on November 8, 1983.

The following parties presented evidence in the form of formal prepared testimony before the Commission: Pacific Gas and Electric Company, the Commission staff, the California Street Lighting Association, Toward Utility Rate Normalization (TURN), Ultra Systems/Occidental G. Thermal, Western Mobile Home Association, the California Manufacturing Association, the Schools Committee to Reduce Utility Bills (SCRUB), Union Carbide/Nabisco/General Motors, the Local Governmental Commission, Contra Costa County, the Association of California Water Agencies, the International Brotherhood of Electrical Workers, the United States Navy, and the Federal Executive Agencies, Lee Lambert and Robert Innes, the University of California, the California Association of Utility Shareholders (CAUS), The California Food Processors Association, the American Gas Association, the Edison Electric Institute, Steven S. Slauson, the Bay Area Rapid Transit System (BART), the California Energy Commission, the City of San Jose, the City of Fremont, Williams Brothers Engineering, the City of Madera, Independent Energy Producers, and the Kaiser Cement Corporation.

The following 24 parties submitted opening briefs:

American Gas Association (AGA)

California Association of
of Utility Shareholders (Shareholders)

California City/County Street Lighting
Association (CAL-SLA)

California Energy Commission (CEC)

California Farm Bureau Federation (CFB)

California Manufacturers Association (CMA)

California Public Utilities Commission (staff)

City and County of San Francisco
(San Francisco)

City of Madera

City of Palo Alto

City of San Jose (San Jose)

Contra Costa County and The Local
Government Commission (LGC)

Edison Electric Institute (EEI)

Lee M. Lamber and Robert D. Innes

Industrial Users (IU)

Independent Energy Producers (IEP)

San Francisco Bay Area Rapid
Transit District (BART)

Schools Committee For Reducing Utility
Bills (SCRUB)

Secretary of Defense/Federal Executive
Agencies (Executive Agencies)

Southern California Edison Company (SCE)

Toward Utility Rate Normalization (TURN)

Ultra Systems Incorporated and Occidental
Geothermal Incorporated

United States Black Chamber of Commerce,
et al., (Public Advocates)

Western Mobilehome Association (WMA)

The following 16 parties submitted reply briefs:

California Association of Utility Shareholders (CAUS)
California Manufacturers Association (CMA)
California Public Utilities Commission (CPUC)
California Retailers Association (CRA)
City of Palo Alto
City of San Jose
Contra Costa County and the
  Local Government Commission, Inc. (LGC)
Independent Energy Producers (IEP)
Industrial Users (IU)
International Brotherhood of Electrical
  Workers, AFL-CIO, Local 1245 (IBEW)
Kaiser Cement Corporation
Pacific Gas and Electric Company
Schools Committee for Reducing Utility Bills (SCRUB)
Toward Utility Rate Normalization (TURN)
Ultra Systems Incorporated and
  Occidental Geothermal, Inc.
Western Mobilehome Association (WMA)

III. RATE OF RETURN

Before describing and evaluating the specific recommendations presented by parties in this proceeding, it is important to reiterate our policy objectives in establishing a fair and equitable return on capital. Although there is some disagreement among witnesses as to the cost of new debt for 1984 and 1985, by far the primary area of controversy is the appropriate rate of return on common equity during the test year period. Part of this controversy reflects the fact that the cost of equity capital, relative to other categories of utility expenses, is more problematic and difficult to estimate. However, we believe that part of the controversy also centers around disagreements, and perhaps misperceptions, concerning the policy objectives of this Commission in establishing a rate of return.

Simply stated, our objective is to authorize a return to common equity owners that will be commensurate with the market returns on investments having corresponding risks during the test period. We believe that, in establishing an authorized return which appropriately reflects the market cost of capital, we are placing utility management on a sound financial footing in terms of competing for and attracting capital. This does not mean, however, that PG&E or any utility will necessarily earn its authorized rate of return during the test year--that depends on the ability of PG&E's management to effectively and efficiently utilize its resources over both the short- and long-term, and the reasonableness of the expense estimates and allowances for the test period.

We view the rate of return portion of this proceeding as part of the overall process of prospective ratemaking. As we have discussed in establishing test year revenue requirements for other expense categories, prospective ratemaking does not "look back" in time and adjust future revenue requirements such that actual utility expenditures are always recovered 1-for-1 through rates. If utility management decides to tradeoff among expense categories in response to changing circumstances or management priorities, they are awarded that flexibility.

However, as also discussed in this decision, prospective ratemaking does not provide cost recovery in future years for activities that were budgeted for, but not performed in previous test years. Nor does prospective ratemaking require the utility to reimburse ratepayers if their overall expenditures, or expenditures within particular budget categories, are lower than projected during the rate case.[1] To do so would be tantamount to establishing a 1-for-1 balancing account for all utility expenditures and activities.

Similarly, we believe it is inappropriate to establish a higher rate of return for a prospective test year in order to compensate utility shareholders for the fact that utility earnings were lower than the authorized rate in previous years. Nor do we expect shareholders to reimburse ratepayers directly (or indirectly by depressing future authorized returns) when the utility earns in excess of its authorized rate of return.

The task before us, then, is to estimate the cost of PG&E's capital, in particular the cost of equity capital, in the market over the next two years. To do so, we must identify the risks for which investors require compensation, evaluate the relative magnitude of these risks for PG&E over the test-year period, and quantify these observations into an authorized rate of return on common equity and total capital. We are guided by the following three major considerations.

[1] Conservation and load management programs represent the only areas of utility activities where management is expected to spread the "budget" or else carryover funds for future program activities. See our discussion of these issues in Section V of this order.

First, we believe that, all other things being equal, the cost of equity capital varies in the same direction as changes in the general level of inflation and interest rates. Although the absoute magnitude of that relationship or "risk premium" is an issue of controversy, the general principle is not only consistent with financial theory, but also acknowledged by this Commission and parties to this and prior rate of return proceedings.[2] Second, we recognize that the market cost of equity capital for a particular utility reflects other risks, such as the exposure of a utility's earnings to variability in fuel costs, sales levels, as well as uncertainties regarding the technical feasibility and/or cost recovery of prior capital investments. Hence, our determination of an appropriate rate of return must also take into consideration the extent to which these risks have abated, increased or remained unchanged, and the probable direction of change during the test year period.

Finally, we believe that the judicious application and interpretation of financial models can aid us in quantifying the overall balance of these risks, and the market cost of equity capital during the test period. It must be emphasized, however, that the models themselvs may not accurately reflect all of the intricacies of financial markets. Further, the assumptions used in applying a financial model or formula must be carefully evaluated for reasonableness before this Commission places substantial weight on the numeric results.

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2 PG&E's supplemental exhibit in this proceeding, for example, adjusts the utility's originally requested return on equity downwards from 19% to 17.5% to reflect lower inflation and lower costs of new debt. This Commission also acknowledged the relationship between the cost of equity capital and the level of interest rates in D.93887, PG&E's 1982 test year rate case. Our authorization of a 16% return on equity for test year 1982, an increase of 2 percentage points from the prior PG&E rate case, was clearly influenced by the reality that PG&E's new bond and preferred stock issues had increased considerably in 1981, and that the higher level of interest costs was projected to persist in 1982.

A. Summary of Positions

The issue of the appropriate rate of return and cost of capital for PG&E in the test year was contested by five parties in this proceeding. The major differences between the parties centered upon the appropriate cost of equity. Each party estimated a range of costs using one or more financial modeling techniques. The results of their analysis and their recommendations are summarized below.

Party	Range of Results	Recommended Return on Common Equity
Shareholders		18.0%
PG&E--initial	17.68%-19.61%	19.0%
supplemental	15.55%-19.08%	17.5%
Staff	15.19%-16.16%	15.5%-16.0% (15.75% midpoint)
Federal Agencies	15.2 %-17.3 %	15.5%
Lambert & Innes	12.63%-14.06%	13.6%

As indicated below, there are also differences among parties with regard to the cost of new debt and preferred stock issuances for 1984 and 1985. Staff, PG&E, and Lambert and Innes assumed new preferred stock costs to be 25 basis points lower than new bond costs for each year. Federal Executive Agencies estimated preferred stock costs to be 150 basis points lower than bond costs.

Party	Incremental Debt Costs 1983	1984	1985
Shareholders (CAUS)			
PG&E--initial	14.25%	12.5 %	12.00%
supplemental	13.5 %	13.5 %	13.5 %
Staff	12.5 %	12.0 %	12.0 %
Federal Agncies	12.5 %	12.0 %	12.5 %
Lambert & Innes	12.17%	10.36%	10.76%

Minor differences also exist between PG&E and staff in projecting the dollar level of new financings for 1984 and 1985. There is general agreement, however, that the appropriate capital ratios for 1984 and 1985 are:

Bonds	44.00%
Preferred Stock	13.75%
Common Stock	42.25%

B. Position of PG&E

PG&E's rate of return witness, Gordon R. Smith, sponsored two exhibits: PG&E's original Exhibit 5 prepared in early fall 1982, and an updated Exhibit 5A, prepared in early 1983.

As indicated above, PG&E modified its original forecast of debt costs for the test and attrition year (which had been based on econometric forecasts) and adopted instead a significantly higher projection of 13.5% for that period.

Smith explains the basis for these changes as follows:

(Smith) "We felt--I felt when we made our updated exhibit that 14.25, which we had built into our rate of return for 1983, was too high.

"I was also concerned that 12.5, 12.25 going down in '83/'84 was too low. So, I did not use the DRI method that we had used when we filed the NOI, but rather, just relied on a variety of conversations and concerns--a gut feeling, if you will--for what interest rates might do.

(Day) "Is there any way you could describe for the Commission or some other interested observer of this process to duplicate this process and arrive at the same conclusions that you have about the cost of debt, or is this a uniquely individualistic use of judgment?

(Smith) "Well, there's only one Treasurer at PG&E and you're talking to him, and the

> conversations that I have had with my investment bankers, economists, commercial bankers, in-house econometric staff, and to one individual making forecast on a conservative basis that rates could flare up again to 13.5%."

In its supplemental filing, PG&E also revised its requested return on common equity downward from 19% to 17.5%. Smith derived PG&E's 17.5% return on equity request based on his professional judgment and the application of five methods or models to calculate the required return on equity: (1) the market-to-book ratio, (2) interest coverages, (3) the Discounted Cash Flow (DCF) method, (4) the capital Asset Pricing Model (CAPM), and (5) the risk premium model. The general characteristics of these models, and PG&E's specific application of them, are described below.

The market-to-book ratio method calculates the rate of return on common equity that will equate the current market and book values of a utility's common stock. It is a very simple mathematical formula that, in a somewhat different form, was also used by the CAUS witness to derive his rate of return recommendation. It is bsed on the theoretical premise that, if the utility is earning its market cost of equity capital the market-to-book ratio of its stock should equal 1. Application of the formula, however, adjusts prospective authorized rates of return such that this equality will hold during the test period. Based on this formula, PG&E projects a cost of equity capital of 16.97%.

PG&E also uses an interest coverage formula for projecting the market cost of capital based on a 3-times after-tax interest coverage requirement. Essentially, this method establishes an interest coverage goal and, given assumptions concerning capital structure and debt costs, derives the return on equity that will achieve that coverage ratio. Using this formula, PG&E derives a rate of return on common equity of 18.39%.

Under the discounted cash flow method (DCF) it is assumed that an investor expects a certain long-run growth rate in total earnings, consisting of dividends and capital gains. It is based on the premise that today's market price of stock reflects the value of those earnings, discounted to the present by the cost of equity capital. Assumptions concerning the utility's 1983 dividend yield and earnings growth rate are critical in the application of this model.

PG&E performed three DCF calculations, using three different sets of assumptions. In the first calculation, PG&E estimated a 1983 dividend yield of 9.96%, based on the stock price on January 31, 1983, and estimated an 8.45% growth rate, based on the 1977-1982 observed growth rate in PG&E's dividends. In the second calculation, PG&E used the same growth rate, but calculated a 10.65% 1983 dividend yield bsed on the September 1, 1982 through January 1, 1983 average stock price. In the third calculation, PG&E used a 6.07% growth rate based on an industry average projection by an econometric service, and an 11.68% yield based on the 52-week high-low average stock price in 1982. The result of these calculations yield a cost of equity capital between 17.75%-19.08%.

Under the risk premium approach, common equity investors are assumed to require a premium above returns received by the bondholder in order to compensate the investor for additional risk. Accordingly, applications of this model usually apply a risk premium, based on historical relationships, to the incremental cost of debt projected over the test period. PG&E, however, applies the risk premium model to the utility's embedded cost of det (i.e., the total weighted average cost of debt, including the cost of outstanding debt issuances as well as incremental debt costs). PG&E's risk premium is based on the relationship between common equity and embedded debt costs observed over the 1965-1969 period, a period chosen because of PG&E's financial health during those years. The results of this model project a return on common equity of 18.08% for 1984.

The last method used by PG&E is the capital asset pricing model (CAPM). This model breaks the required return into two components. The first is a risk-free rate of return that investors require on investments for which the risk of not receiving the stated return is negligible. The 90-day Tresury Bill rate is often used as a proxy for a risk-free rate of return. The second component attempts to measure the additional return required to compensate for the risk of a particular asset. Under CAPM, the required equity return is equal to the risk-free return plus a risk component which varies with the market. In CAPM the required return is viewed a moving to a greater or lesser extent with the return on the market. The extent of the correlation between the return on a stock and the return on the market is measured by the firm's "beta".

In applying this model, Smith made one assumption which differs significantly from the CAPM analysis performed by other parties. For the risk-free rate, PG&E uses the T-bill futures rate quoted in the Wall Street Journal on a single day (in January 1983) to imply an annual rate of 10.21%, rather than using a direct projection of the T-bill interest rate for 1984. The resulting rate of return on equity, using the CAPM model, is 15.55%.

In deriving his specific recommendation of 17.5%, Smith also reviews six major areas of risk facing PG&E and their impact on the required return on equity: (1) interest rate fluctuations; (2) inflationary impacts, (3) fuel cost recovery; (4) technological and project recovery risks; (5) regulatory policy risk; and (6) political risk. According to Smith, these risks continue to be substantial and growing factors affecting the required rate of return on equity during 1984 and 1985.

Smith notes that in 1982, for the first time since 1968, PG&E earned very close to the return on equity found just and reasonable. The return on common stock equity in 1982 was 15.8%, which compares favorably with the 16% return on equity found just and reasonable in

D.93887, dated December 30, 1981. However, Smith argues that, while its earnings improved in 1982, the financial markets determined that the utility's overall financial condition had deteriorated. He notes that in 1982, Moody's Investor Service, Standard and Poor's, and Duff and Phelps all downgraded PG&E's preferred stock ratings. According to Smith, "The actions of the three rating agencies demonstrated that PG&E could no longer sustain its Aa bond and A preferred stock ratings without adequate financial performance."

Smith also contends that PG&E's overall risks in the test period remain high despite the earnings performance in 1982. According to Smith, it is an incorrect notion that with the reduction in inflation and capital costs, PG&E's risks have declined. Smith argues that the risk associated with the cost of capital is the risk of fluctuation and volatility in interest rates, and not their absolute level. He also believes that, while general inflation levels have declined, there is an inflationary risk inherent in ratemaking, that the Commission will adopt optimistic estimates of escalation rates in the test year based upon present conditions.

Smith contends there is a substantial and growing risk regarding fuel cost recovery, referencing the Commission's recent decision to increase from 2% to 9% the percentage of PG&E's fuel costs in the fixed AER. According to PG&E, the change in the AER increases risk in a situation where PG&E, despite diligent and thoughtful management, will have minimal ability to control the outcome. The major factors affecting fuels strategy are the weather and world oil prices; PG&E is not clairvoyant concerning the next hydro year, nor is it able to forecast the next international event and its impact on oil prices.

Smith also noted that recovery of the facility charge related to PG&E's Chervon contract remains at risk. Also, the so-called "billing-lag" issue related to gas purchases has placed at least $15 million at risk. According to Smith, these are but two examples of future risks of nonrecovery of fuel-related costs.

With regard to technological and project development risks, Smith asserts that, as the utility develops more alternative generation resources, many with unproven technologies, PG&E faces greater risks of nonrecovery of feasibility study costs as well as costs of development. PG&E notes that under present ratemaking treatment, recovery of these costs is delayed and the AFUDC for unsuccessful projects is disallowed.

As an example of increased project development risks, Smith cites the liquified natural gas (LNG) project, for which the Commission recommended in October of 1982 that PG&E and Southern California Gas Company cease accruing AFUDC and that they file for some sort of rate treatment of the investment costs. He also cites the staff's recommended disallowance of $25-$50 million in the Helms proceeding (A.82-04-12, Exhibit 184) as a further example of the increased risk of nonrecovery of project development costs.

Finally, PG&E argues that regulatory and political risks as well as increased California legislative scrutiny are increasing investors' concerns regarding the ability of PG&E to maintain its earnings level.

C. Position of Commission Staff

The staff's testimony was presented by Linda Gori. She assumed interest rates on new debt financing at 12.5% for 1983, and 12% for 1984 and 1985. This compares with PG&E's updated assumptions of 13.5% for all three years. Gori developed her recommendations regarding the cost of debt in the test year and the attrition year by examining trends in current interest rates and AA interest rate forecasts published by DRI. Specifically, she considered the average of DRI published forecases over the November '82 - January '83 period and added approximately 100 basis points, the observed interest rate spread between AA and A-rated utility bonds over the last couple of years.

Gori tested the reasonableness of PG&E's 25 basis point differential between bond and preferred stock costs by examining the historical spread for PG&E specific issuances over the last 5-10 years. She concluded that a 25 basis point average spread was a reasonable assumption for the test period.

In developing her recommendation for the cost of common equity, Gori utilized various financial models commonly used to estimate the required return. Gori applied a DCF model, but used different input assumptions than PG&E's witness. Rather than relling on the most recent 5-year growth in dividends and earnings, she used a 10-year historical period. Her rationale for using a longer period was that PG&E's recent 5-year dividend growth rate and earnings growth rate during the last 5 years, particularly in 1982, were uncharacteristically high, distorted by PG&E's exceptional earnings in 1982 relative to prior years (43.99% growth in earnings in 1982 over 1981). She maintained that dividend growth could not continue at the recent 5-year growth level without earnings to support such growth. Using a longer-term view, Gori derives an expected dividend growth of

5.5% from past trends. She also derives a "sustainable" growth rate of 4.10% - 5.27% in dividends, based on projections of retained earnings over the test period. The expected 1983 dividend yield used in her DCF analysis (10.62%-10.66%) was based on PG&E's 1982 annual declared dividend compounded by the respective growth rate and the most recent (January 1983) monthly average stock price of $29.00. The results of Gori's DCF analysis yield a range of 15.72% to 16.16% in required return on equity.

As a test of reasonableness, Gori extended her DCF analysis to 18 electric and combination utilities to compare her utility-specific results to utilities of comparable risk. The average investor-required return on common stock of these comparable risk utilities range from 14.32% to 16.17%.

Gori also performed a risk premium analysis, which examined the historical premiums PG&E shareholders received over single A-rated public utility and 20-year government bond yields. She applied the average risk premiums observed during the 1973-1982 period to her projection of incremental debt costs for the test period (12%). The results of her analysis yield a range of equity returns of 15.19%-16.12%.

Gori did not use a market-to-book ratio method or interest coverage formula to estimate the cost of equity capital. In its brief, staff argues that use of these simplistic equations have no theoretical support, and are plagued by a number of serious problems. Due to the powerful external factors in the marketplace which affect stock price, staff argues that use of a market-to-book ratio formula prospectively has little or no practical significance.

Similarly, Gori argues that interest coverage is only one of several financial criteria that rating agencies rely on, and did not base her recommendation on any test for sustainable or increasing bond ratings. Gori did, however, evaluate the implied after-tax interest coverage of her recommendation, and concluded that a 2.76x-2.81x after-tax coverage (corresponding to 15.5%-16% return) compares favorably with the average implied after-tax coverages authorized in past Commission decisions. Her review of after-tax interest coverages for Moody's Aa and Standard & Poor's AA rated utilities also indicated that they are substantially below the 3.0x level used by PG&E, and average 2.59x.

In addition to her quantitative analysis, Gori evaluated the economic conditions and risks facing PG&E in the test period in qualitative terms. She concludes that, on balance, economic conditions facing PG&E have significantly improved:

> "Notable specifics of the improved conditions include: (1) significant declines in inflation and interest rates which are projected to continue or be maintained during the test period; the latter commensurably reduce investors' opportunity costs of common equity; (2) lower financial risk for PG&E's shareholders resulting from the shift in capitalization towards a greater percentage of common equity; and (3) projected improvements in PG&E's cash flow and earnings stability resulting in greater financial flexibility and lower risk to investors in PG&E." (Exhibit 53, p. 4.)

In addition, Gori points out that, as a result of the Economic Recovery Tax Act of 1981, PG&E will continue to derive the cash flow benefits from deferred taxes and investment tax credits during the next 2 yars. Gori calculates that these tax benefits are projected to contribute approximately 18% and 9% of PG&E's total capital requirements in 1984 and 1985, respectively.

With regard to the downgrades in early 1982 of PG&E's first mortgage bonds and preferred stock, Gori provided analysis to illustrate that, as far back as 1979, PG&E's first mortgage bonds were trading at A levels. She argues that the change in rating merely brings the rating more in line with the debt cost the utility was atually experiencing, and will have no significant increase in either the debt cost or the risk facing the utility as a whole. She points out that the financial community has long been concerned about particular aspects of PG&E's construction programs, particularly with respect to the commercial operatin of Diablo Canyon. This one project has been cited by financial analysts on a number of occasions as being one of the major uncertainties facing PG&E. With little or no change in the status of Diablo Canyon as of the time of her testimony, but with significant improvement in many of PG&E's other financial indicators, staff concludes that the downgrading is simply a reflection of past uncertainties and cannot outweigh the vast improvements in PG&E's financial condition.

On the subject of financial risk, staff describes in detail the numerous regulatory mechanisms which serve to protect utility earnings from unanticipated variations in fuel-related costs, fuel mix, sales levels and inflation. Gori also described the regulatory procedures designed to improve the timeliness of regulatory rate recognition.

Gori's final recommendation of 15.75% (the midpoint of her 15.5%-16% recommended range) places primary weight on the range of results from her DCF calculations, and her overall consideration of the risks facing PG&E in the test year.

D. Position of Federal Executive Agncies

The FEA position was presented by Dr. John B. Legler. Based upon his review of econometric forecasts for debt costs and newly issued public utility bonds for other utilities, Dr. Legler concludes that the Commission staff witness' debt cost of 12.5% for 1983 and 12% for 1984 are both reasonable. However, his review of more recent DRI forecasts and forecasts by Wharton EFA, Inc. lead him to conclude that incremental debt costs are likely to increase in 1985 by .5% compared to 1984. He therefore recommends a 12.5% cost of new debt for 1985.

Dr. Legler also examined recent (1983) issuances of preferred stock within the overall utility industry (not PG&E), and adopted a 150 basis point spread between preferred stock and bond costs in his analysis.

Dr. Legler primarily relied on the DCF method in estimating PG&E's cost of equity capital and in evaluating the reasonableness of staff's and PG&E's recommendations. He examined PG&E's historical dividend growth rates, projections of retained earnings and growth rate forecasts provided by Merrill Lynch, in order to forecast a growth rate in earnings over the test period. Considering both the historical data and relevant forecasts, Dr. Legler concludes that a 5%-5.5% growth rate is reasonable. He argues that Smith's use of a 8.45% historical growth rate in making his DCF calculation is unrealistically high: PG&E would have to earn an average return on equity of 25.6% in order to sustain that dividend growth rate into the future. Using an expected 1983 dividend yield of 10.5%-10.57%, Dr.

Legler calculates a return on common equity of 15.5%-16.07%. He supports the reasonableness of this range by applying the DCF analysis to a group of A-rated electric utilities, and by evaluating the relative risk of PG&E, based on financial structure, variability in earnings, betas and other risk measures.

Dr. Legler also evaluated Smith's use of the embedded debt costs (rather than new debt costs) in his risk premium analysis. He points out that, even if interest rates on long-term debt were to decline substantially, applying a risk premium to embedded debt costs would not result in a lower cost of equity. Dr. Legler also expressed general reservations about the risk premium method, which stem from his observation that premiums can and do vary considerably over time. He performed a risk premium analysis that resulted in a rate of return of approximately 15.25%, based on Gori's projected bond yields. However, Dr. Legler placed primary reliance on the DCF method in presenting his recommendation of 15.5% return on equity.

E. Position of Lambert and Innes

Lee M. Lambert and Robert D. Innes, individual intervenors with academic and consulting experience in financial analysis, also appeared to testify regarding the appropriate cost of capital for PG&E. They based their incremental debt costs for 1984 and 1985 upon the March 1983 DRI forecasts for AA bonds, 10.16% and 10.56%, respectively. They argue that staff's method of averaging DRI predictions discounts the value of recent information and DRI's ability to incorporate all relevant data in its most recent forecast. They adjust DRI's forecast by 20 basis points, the average premium between AA and A bonds over the last 10 years, based on monthly observations. This process arrives at debt cost estimates of 10.36% for 1984 and 10.76% for 1985.

Lambert evaluates PG&E's financial condition, specifically in light of Smith's comparative evaluation of risk and his conclusion that PG&E is riskier than the average utility. Lambert examines the ranking of the utility vis-a-vis 40 others a set forth by independent services. Based on this data, the "A" rating assigned to PG&E by Standrd and Poors ranks the utility in an eleven-way tie for tenth place. Value Line assigns PG&E a beta of .60, which ranks it among the 12 least volatile utilities. Finally, Lambert notes that PG&E ranks 45th of 50 companies in its use of debt, where a lower use of debt implies less financial risk relative to comparable utilities. In sum, Lambert conludes that, contrary to the utility's claim, PG&E's stock is less risky than the average utility.

Innes presents three basic methods for evaluating the appropriate return on equity, including the DCF method, a CAPM method and a calculation of the appropriate return based on interest coverages. In his direct testimony, Innes expresses general reservations in placing primary reliance on the DCF method. His main objection to this approach is that it accounts for current conditions only indirectly and reliis on a variety of historical data that may not reflect investors' expectations for the future. In particular, Innes argues that inflation changes must be incorporated by explicit adjustments to the growth rate employed in the DVF analysis.

To make this adjustment, Innes selects two periods 1968-1973 and 1975-1978 which he considers to represent inflation conditions similar to the present. He calculates the average dividend growth rate during those periods for PG&E and for the 18 comparable utilities used by Gori. The average growth rate for the sample, including PG&E ranged between 2.76%-4.15%. When applied to an average current yield of 10.5%, this method yields a range of 13.55%-15.08% in the required rate of return on common equity.

Innes also presents the results of a CAPM analysis, although his assumptions differ from those used by PG&E. Rather than using a 10.21% T-bill futures rate, Innes uses the January 1983 forecast of 90-day Treasury bill rates for 1984 and 1985 (8.5%) and the 90-day T-bill rate as of April 12, 1983 (8.2%).

Innes calls into question PG&E's use of T-bill futures as an unbiased predictor of future T-bill rates, citing both economic theory as discussed in recent academic literature and his own analysis. Innes formulated a T-bill forward position which is essentially the same as entering into and paying for a T-bill futures contract. The result of his analysis is that such a forward position itself contains a premium over the actual T-bill rate, but more importantly, it demonstrates that the T-bill future rate is still higher than the forward position rate (Exh. 74). This would demonstrate that there is in fact a substantial premium attached to the T-bill futures rate because of the necessary speculation forward in time.

In applying the CAPM model, Innes also attempted to quantify the changes in PG&E's beta (measure of overall risk) due to projected improvements in its capital structure over the test year period. His results reduce the beta only slightly below the .60 assumed in PG&E's analysis. Hence, the primary difference between Innes' results (13.31%-13.46%) and PG&E's (15.55%) stems from the use of a lower risk-free rate in the CAPM model.

Lambert and Innes also question PG&E's assertion that an after-tax interest coverage ratio as high as 3.00 is needed as a criterion for AA standing. Their arguments and analysis of past coverage ratios parallel those of staff on this issue. Although Lambert and Innes present a range of 12.63%-14.06% in required return based on this method, they emphasize that little weight should be placed on the conclusions implied by this approach. Lambert and Innes' overall recommendation of an 13.6% allowed return on equity places primary reliance on the results of their CAPM analysis.

F. Position of the California Association of Utility Shareholders (CAUS)

Shareholders presented their position through CAUS' executive director, Phillip C. Presber. He recommended a rate of return on common equity for the test period of 18.0%. His analysis was based primarily on consideration of the appropriate earnings-price ratio for the utility. Presber calculates the earnings per share and dividends, and the resulting book value required to maintain an earnings-price ratio recently experienced by PG&E. This approach is similar to PG&E's market-to-book ratio approach, where market performance goals are set and a rate of return necessary to achieve that goal is derived. This calculation yields a return on equity of 17.5% in 1984 and 17.4% in 1985. Presber recommends an overall return of 18% to "compensate for investor expectations regarding earned versus allowed returns and for issuances of new shares". (Exhibit 48, p. 33)

According to CAUS, PG&E shareholders suffered during the 1974-1982 period when regulation was generally unfair to shareholders. In balancing short-term and long-term costs, CAUS argues that the Commission must weigh the alleged advantages of establishing a low rate of return against the fact that when an authorized return allowance is below market demanded return, the dilution of new issues will be an added cost of doing business for not only the year of the issue but every year thereafter.

CAUS urges the Commission to not be misled by predictions of lower interest rates through 1985 and to not be lulled into a false sense of satisfaction because PG&E nearly made its authorized rate of return for one year. CAUS points to the negative potentials ahead for PG&E. According to CAUS, not only will the state legislature pass strong consumer legislation, but the costs of Diablo and Helms and the LNG facility are not in rate base. CAUS contends that the market has not yet reacted to possible Diablo Canyon, Helms Power Plant, and LNG project cost disallowances and ECAC formula adjustments.

G. Position of City of San Francisco (San Francisco)

San Francisco notes that the staff rate of return witness correctly summarized the improved economic conditions that PG&E now faces.

Accordingly, San Francisco argues that the significant declines in inflation and interest rates should yield significant decreases in PG&E's allowed return on equity. The Commission should treat PG&E and the public fairly and consistently. In times of high interest rates and high inflation PG&E has been well treated by the Commission. Now that inflation and interest costs have abated the Commission should treat the public fairly and significantly reduce the returns and rates granted in the last case.

San Francisco further notes that, in 1982, the voters of San Francisco passed Proposition N which asked the Public Utilities Commission to roll back the 1981 PG&E increases and carefully review the PG&E rate structure. Accordingly, San Francisco concludes that current conditions compel significant review and reduced profit levels.

H. Position of Toward Utility Rate Normalization (TURN)

TURN did not present a witness but recommends a 14% return on common equity.

TURN believes that current conditions require a substantial reduction in PG&E's presently authorized return on equity of 16%. Interest and inflation rates have declined significantly from those prevailing at the time of D.93887. TURN notes that PG&E's stock (now split) is selling closer to book value than it has in years, and some shares have been issued by the utility at prices in excess of book. TURN considers this quite remarkable considering the uncertainties that exist regarding the reasonables of the construction costs for Diablo Canyon and Helms. TURN concludes that investors view PG&E as a strong company, in spite of the errors of the past.

While TURN acknowledges that further delays are always possible and that Diablo Unit #2 may not be quite ready TURN believes that Diablo and Helms will be in operation before the year is over. The long awaited arrival of these plants will provide a substantial boost to the utility's cash flow. TURN maintains that the potential for cost disallowances on these projects should not be considered as grounds for authorizing a higher-than-normal return. According to TURN, any such disallowances would be the result of the utility's own mistakes, and should not lead to higher costs for consumers.

I. Discussion

In evaluating the recommendations presented by the witnesses, we have carefully examined all the quantitative and qualitative analyses presented in this case. Our lengthy description of these analyses, as well as our discussion below, is designed to aid parties in this and future proceedings in fully understanding our reasoning in reaching a determination on PG&E's cost of capital.

Turning first to the question of the future cost of long-term debt, we are unpersuaded by PG&E's reliance on "gut feeling" in this matter. PG&E's projected debt costs are unsubstantiated and, in fact, contradicted by a careful review of the evidence in this proceeding. Further, we find it unsettling that, while PG&E considers DRI forecasting sufficient to use on the day-to-day basis in its financial planning models, PG&E did not retain that confidence in DRI when the time came to revise its rate of return request.

Innes' objection to "averaging" updates in DRI forecasts of AA bond rates is well taken. At the same time, we are concerned that his reliance on a single forecast in time by a single econometric service will not properly reflect that service's own forecasting lags, differences in opinions among services, and updates made subsequent to the forecast used by witnesses in their testimony. Parties are free to present viable and practical alternatives to address these concerns in future rate case proceedings.

With regard to the premium between A and AA rates bonds, we conclude that Innes' use of a 10-year average premium significantly understates the more recent premiums observed in the market. Finally, we are persuaded by Dr. Legler's careful review of newly issued debt costs, consideration of DRI's updates and use of a second econometric service in this projection of PG&E's debt costs for 1985.

These considerations lead us to conclude that a rate of 12.5% for 1984 and 1985 represents a reasonable supportable estimate of PG&E's incremental debt costs in the test period. For 1983, actual debt costs will be used. These costs will be applied to the 1983, 1984, and 1985 revised and updated projections of PG&E's financings, presented in Exhibit 245, page 12.

On the issue of preferred stock costs, we consider the use of PG&E-specific differentials, observed in the market, a better indicator than Dr. Legler's use of industry-wide data for only one year. Hence, we adopt a rate for newly issued preferred stock of 25 basis points below PG&E's incremental cost of debt.

Turning to the cost of common equity, we will first evaluate the quantitative analysis presented in this proceeding, highlighting the strength and weaknesses in each witness' choice of input assumptions and modeling techniques. This discussion will serve to narrow the wide range of returns presented in this proceeding to a range which we feel best represents the judicious application of financial modeling techniques. Second, we will evaluate the qualitative discussion of risk presented by the parties, in order to determine where within that range PG&E's market rate of return lies. Our final determination will reflect our best judgment concerning the relative weight of all the factors presented in this case.

With regard to PG&E's quantitative analysis, we can place very little weight on the results of its market-to-book ratio or interest coverage calculations in formulating our decision. We find the criticisms concerning the theoretical appropriateness of these formulas persuasive. In particular, we conclude that the use of a market-to-book ratio formula provides little or no practical guidance in estimating PG&E's market rate of return on equity. For similar reasons, we place little weight on the calculation performed by the

CAUS witness, in deriving an 18.0% rate of return on equity. In future rate of return proceedings, parties should not use or present the results of, a market-to-book ratio method in developing rate of return recommendations.

We do not believe that interest coverage ratios measure the market cost of capital. In addition, we agree with staff, Dr. Legler, Lambert, and Innes in their criticisms of PG&E's conclusions that a 3.00x after-tax interest coverage is required to achieve an AA debt rating. Furthermore, the ability of a utility to maintain or improve its bond rating is a general consideration, but not a test of reasonableness in our rate of return deliberations. We note that PG&E's presentation of this interest coverage requirement was similarly discounted in our deliberations during its 1982 rate case (D.93887, mimeo, p. 51). Accordingly, interest coverage ratios should not be presented in future rate of return proceedings as a method for estimating the market cost of capital.

Our examination of PG&E's discounted cash flow analysis reveals significant biases in the input data. We are convinced by both Dr. Legler's analysis and by staff's articulate critique in its opening brief (pp. 24-25), that PG&E's analysis uses unrealistically high dividend growth factors and selects data to maximize the resulting return on equity.

We also agree with staff that PG&E's risk premium analysis constains a fundamental bias towards higher rates of return because it is improperly based on the embedded cost of debt. The use of embedded debt costs contradicts the theoretical premise underlying this model. As discussed earlier in this decision, we believe that, all other things being equal, the cost of equity capital varies in the same direction as changes in the general level of inflation and interest rates. A reasonable application of this model would examine risk premiums relative to a utility's incremental, not embedded, debt costs. We also conclude that PG&E's application of the CAPM model improperly uses a T-bill future rate, which has been demonstrated to be a biased predictor of actual T-bill rates.

Turning to Innes' analysis, we concur with his general observations concerning the limitations of DCF analysis. While we commend his attempt to modify the model to adjust for changes between historical and future inflation rates, we believe that the modifications to the DCF model he employed are questionable. In particular, we do not consider the two time periods he selected to derive his adjustments as particularly representative of today's inflationary conditions. Nor do we find his arguments for selecting those periods persuasive. We suggest that a more appropriate, and less arbitrary, method of taking inflationary trends into account would be to calculate the real growth rate in dividends in the past, and adjust that rate for inflation rates expected in the future.

In his application of the CAPM model, Innes uses relatively low T-bill rates based on the rates prevailing as of April 12, 1983 and a January 1983 projection of 1984 rates. We believe that the use of current debt costs and a single projection early in 1983 does not appropriately reflect projections of debt costs in the test year. As a result, we conclude that Innes' CAPM analysis yields results that are unreasonably low, due to his choice of input assumptions.

Although Dr. Legler and Gori used somewhat different input assumptions in their applications of the DCF and risk premium methods, the results of their analyses were very similar.[3] We find that both witnesses clearly explained and supported their choice of assumptions based on combination of financial theory and common sense. However, unlike these two witnesses, we do not place primary weight on the results of the DCF model, relative to the risk premium method. We feel that both models have their relative strengths and weaknesses.

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3 For the reasons discussed above, a risk we do not place much weight on cost of capital analysis in which premium or CAPM model is applied to current yields. Hence, this range reflects only risk premium analysis where Dr. Legler applied a premium to projected debt costs.

The results of their analyses, giving equal weight to both methods, yield a range of approximately 15.2%-16.2%.

In general, we find that PG&E's choice of modeling techniques and input assumptions maximizes the resulting return on equity. Innes' analysis, on the other hand, applies unique adjustments to traditional methods and uses debt costs which we believe bias his results downwards. We encourage all parties to continue to use and refine the DCF, CAPM, and risk premium models in ways that are theoretically sound and practical. However, on the basis of our discussion above, we believe that the results of staff's and Dr. Legler's analyses provide us with the most supportable range of quantitative results, 15.2%-16.2% as a guide for determining PG&E's authorized return on equity.

In addition to presenting quantitative analysis, witnesses in this proceeding presented a considerable amount of qualitative information concerning the risks facing PG&E relative to other utilities, previous years, and future trends. We consider this qualitative assessment to be very important in our final determination. As indicated above, the range of reasonable results based solely on the quantitative analysis is from a slight increase in PG&E's current authorized return, to a significant decrease. Our final determination must reflect our best judgment as to the magnitude and direction of risks facing PG&E over the next two years.

First, we turn to Smith's argument that, despite improved earnings performance in 1982, PG&E's overall financial position has deteriorated. We do not find Smith's arguments on this issue very persuasive. We agree with staff's conclusions that the actions of the rating agencies in 1982 represented an adjustment already reflected in PG&E's debt costs as far back as 1979.

There are a number of other indications of financial improvement for PG&E on the horizon as well. PG&E's beta, a commonly used measurement of risk in the investment community, decreased from .75 to

.60 at the beginning of 1983. In fact, PG&E projects additional internal generation of cash due to deferred taxes in the range of $335 million in 1983, $250 million in 1984, and $154 million in 1985.

While we agree that the significant increase in PG&E's earnings performance in 1982 should not be overplayed, we note that PG&E was recently able to sell common stock above book value for the first time since 1964. The recent success of PG&E in increasing its stock price would indicate the utility is at or very close to earning its true cost of capital as determined by the market.

Smith also argues that the risks associated with fuel cost reecovery, technological and project development risks, as well as overall regulatory and political risk, are actually increasing for PG&E. Contrary to PG&E's arguments, we find that our ratemaking procedures protect the utility's earnings from a whole range of variables, including fuel price, fuel mix, sales level, inflation, and the timeliness and predictability of regulatory rate recognition.

Specifically, the Purchase Gas Adjustment Clause (PGA) insures that the utility will collect in rates all increases in the cost of gas supplies through the use of a balancing account; the ECAC procedure insures that PG&E will collect in rates 91% of any unforecasted increase in the cost of electric generation due to increases in fuel cost and/or fuel mix by use of a balancing account; rate base offset proceedings allow the utility to file immediately for a rate increase upon the completion of a major plant addition, rather than waiting for the next general rate case; the rate case plan guarantees the utility timely processing of general rate case applications at regular intervals which recently required updating of data at the end of the public hearings, and the Supply Adjustment Mechanism (SAM) proceeding guarantees that the utility will be compensated for its margin on natural gas sales that may be lost due to sale fluctuations. We also note that, since PG&E' last general rate case, two additional regulatory mechanism have been put into effect: the Attrition Rate Adjustment (ARA) procedure, which provides for an automatic increase in rates between general rate cases to compensate for effects of inflation; and the ERAM procedure, which protects the utility from the possibility of the loss of fixed cost recovery due to fuctuations in electric sales levels.

PG&E's argument that fuel costs are disallowed on the basis of hindsight and that "perfection" is the required standard in ECAC proceeding has no factual basis and is a misrepresentation of the "reasonableness review" procedure. So long as PG&E makes a clear and convincing showing to justify its actions, it does recover all reasonable fuel related costs.

The magnitude of risk which our reasonableness review represents to PG&E's shareholders is best put into perspective by recalling that PG&E has sustained disallowances of only $13.8 million, or 9/1000 of a pecent of fuel-related expenditures in ECAC in the entire time that procedure has been in existence.

With regard to our decision to increase the percentage of fuel costs in the AER, Smith fails to note that we explicitly rejected the option of phasing out the ECAC procedure, and adopted a minor modification to the AER/ECAC allocation instead.

As stated in D.83-08-048, we "exercised caution in making our deliberations" and based our revisions and earnings cap on a criterion of maintaining, not increasing, PG&E's cost of capital (D.83-08-048, mimeo, p. 21a). Furthermore, under the AER procedure, PG&E has an opportunity to increase its earnings by efficiently managing its fuel cost to a level lower than that predicted in the annual ECAC proceedings.

Turning to PG&E's contention that feasibility studies and project development risks for projects later abandoned pose major problems for the utility, we should observe that shareholder acceptance of these risks for preconstruction costs under used and useful principles is recognized in the rate of return authorized. Moreover, in recent years, we have granted exceptions to these principles by allocating some of the risk and cost of abandoned projects to the ratepayers.

We conclude that PG&E has not sustained unreasonable financial risk by reason of the Commission's current policy on preconstruction cost, nor has the policy in any way inhibited development of alternative and renewable resources. Quite the contrary, it has encouraged and provided a useful incentive for the utilities to move away from large capital intensive conventional ~~resource power~~ plants. We note further that PG&E has waited, in some instances, as long as ten years, before requesting recovery of abandoned project costs. Thus, any increased financial risk perceived by PG&E is arguably due to PG&E's delay.

We do not have a precise method of quantifying and incorporating all of the above considerations into a specific rate of return on equity. However, in this case we do believe that a reasonable return lies within, and not at the extremes of the 15.2%-16.2% range. The high end of the range is inconsistent with the evidence in this case that PG&E can meet its cost of equity requirements with a reduction in its current authorized rate of return on equity. This proposition is supported by improvements in the utility's financial position, and by improvements in the condition of the utility industry as a whole. PG&E's witness on the cost of capital conceded that a number of the factors which create more risk and thus higher costs of capital for the utility have abated in recent years. For instance, the PG&E witness conceded that interest rates and inflation are lower and thus more favorable for the utility industry than they were two years ago, and that legislative risks have declined as a result in the decrease of activity in the Legislature regarding utilities. We have carefully considered the level of these risk, along with the ratemaking devices which have been created to minimize negative financial impacts of uncertainty upon the utility.

At the same time, however, we agree with PG&E that interest rate volatility and uncertainty concerning the level of inflation over the next two years is an ongoing, perhaps increasing risk to PG&E investors and to the utility industry as a whole. This is evidenced by our adoption of a 12.5% cost of debt for 1984 and 1985, rather than some of the significantly lower predictions made in early 1983.

J. 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 12.45% for 1984 and 12.53% for attrition year 1985, providing a 15.75% 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. We believe our adopted rate represents a modest reduction in the cost of common equity consistent with market trends.

The following table sets forth the adopted rate of return which assumes that all new long-term debt for 1984 and 1985 will sell at an interest cost of 12.5% and preferred stock at a dividend rate of 12.25%.

Also, PG&E informed the Commission that $75 million of 8-year Eurobonds were sold on October 13, 1983. The effective cost to PG&E is 12.67%. Both of these offerings are reflected in the adopted results.

PACIFIC GAS AND ELECTRIC COMPANY

Adopted Rate of Return
Test Year 1984
Attrition Year 1985

Component	Capital Ratio	Cost Factors	Weighted Cost
Average Year 1984	%	%	%
Long-Term Debt	44.00	10.22(a)	4.50
Preferred Stock	13.75	9.44(a)	1.30
Common Stock Equity	42.25	15.75	6.65
Total	100%		12.45%
Average Year 1985			
Long-Term Debt	44.00	10.37(a)	4.56
Preferred Stock	13.75	9.57(a)	1.32
Common Stock	42.25	15.75	6.65
Total	100%		12.53%

(a) Assumes long-term debt cost of 12.5% and preferred stock cost of 12.25% in 1984 and 1985 and actual 1983 debt and preferred stock costs.

Because we have reduced the rate of return below the return authorized in PG&E's last general rate decision, the Annual Energy Rate (AER) is affected accordingly. Today's authorized return results in an AER reduction of $55,000, which will be reflected in the authorized revenue requirement.

K. Financial Attrition

Based on the adopted cost of long-term debt and preferred stock, the adopted allowance for financial attrition is set forth below:

PACIFIC GAS AND ELECTRIC COMPANY
Adopted Allowance for Financial Attrition
Attrition Year 1985

	Weighted Cost		
	1984	1985	Difference
Long-term Debt	4.50	4.56	.06
Preferred Stock	1.30	1.32	.02
Common Equity	6.65	6.65	-
			.08%

The above allowance will be included in our adopted Attrition Rate Adjustment (ARA) calculation which is discussed later in this opinion.

IV. RESULTS OF OPERATIONS

A. Specific Policy Issues

1. Escalation Factors

Most of the expense data in this proceeding is presented in 1981 dollars. To obtain revenue requirements for the test year and attrition year, these expenses must be increased by escalation factors to represent inflation in 1982, 1983, 1984, and 1985. Since utility expenses are broken into direct labor and nonlabor components, separate escalation factors are developed for each component.

The labor component refers to PG&E's direct labor. The nonlabor component covers materials and supplies and includes indirect labor associated with these items.

a. Labor Escalation

We have reviewed the results of PG&E's labor negotiation which were concluded following submission of the main evidentiary hearing. We find the results of these negotiations reasonable and will include these in our adopted results. It should be noted that our adoption of the results of these negotiations should not be construed to mean that this Commission automatically will adopt the results of all labor negotiations. On the contrary, we will disallow for ratemaking purposes any settlement which we consider unreasonable.

We note that during the course of this proceeding, neither the staff nor PG&E presented detailed analyses of the various wage and salary levels paid to PG&E employees.

We are concerned that the process of escalating wage and salary levels by a certain escalation factor (often the actual wage increase negotiated by PG&E and the union is used for this process), can result in significant increases in the overall level of wages and salaries through the years without any review by the Commission as to whether or not the salaries and wages paid are in fact reasonable when compared to wages and salaries in the marketplace for similar types of work.

The staff has concluded that examination of the reasonableness of wage and salary levels can be accomplished within the context of a general rate case and that this should be done at least on an occasional basis in general rate case proceedings. PG&E already performs comparable wage studies based on west coast and regional wage comparisons. Inasmuch as these studies have to be prepared every year for PG&E to participate in wage and salary negotiations with the unions that represent its employees, these studies are available on a current basis for presentation in Commission proceedings.

We will expect in PG&E's next general rate case proceeding a presentation of levels of wages and salaries estimated by the utility for comparison with similar wages and salaries paid in the marketplace. This will be a check upon the routine procedure in general rate cases of simply escalating all salaries by a certain labor escalation factor. In this way, it will be possible on a more specific basis to see if the amounts allowed as labor increases in the past have in fact resulted in reasonable levels of wages and salaries being provided to PG&E employees. It also provides the opportunity to see whether or not such overall escalation has resulted in excessive increases in any particular wage or salary category where comparable salaries in the marketplace have not risen at the same rate. Without question, a detailed study of every single salary scale and job classification in PG&E is a mammoth undertaking. However, the utility and the staff should be able to examine the relevant comparable wage studies and arrive at some means of making a comparison that can be useful for the Commission's purposes.

As reviewed by staff, we will adopt the following escalation factors, resulting from PG&E's labor negotiations which concluded after submission of the main evidentiary phase of this proceeding. These escalation factors relate to PG&E direct labor expense only.

Pacific Gas and Electric Company
Labor Escalation Factors
Test Year 1984

Year	Percentage
1982	11.22
1983	7.00
1984	5.50
Compound through 1984	25.55
1985	6.50
Compound through 1985	33.71

The 1984 and 1985 labor escalation rates reflect the August 30, 1983, settlement with the union. This settlement provides for a 5.5% increase in 1984 and a cost of living adjustment (COLA) for 1985. The amount shown for 1985 is based on the CPI-W, included in the COLA, as forecasted by DRI. The final labor escalation rate for 1985 will be determined consistent with our adopted ARA procedure which is discussed later.

b. Non-Labor Escalation

This issue was vigorously debated. Application of the staff-recommended escalation rate to the PG&E estimates of test year expense in 1981 dollars provides a revenue requirement which is $21.9 million lower than if PG&E's escalation rates were used. This escalation factor is applied to all expenditures other than direct labor. The revenue requirement varies by $4 million for each 1% change in the rate.

The staff's recommended method for determining non-labor escalation is to use the Modified Producer Price Index (MPPI). The process used to derive the MPPI is to utilize the standard Producer Price Index published by the econometric forecasting services and, on the basis of judgment, eliminate items that are inappropriate to utility operations and expenses such as pharmaceuticals, leather goods, and fuel costs covered by ECAC. With the elimination of the inappropriate items, the sub-indices of the overall index are recalculated by adjusting their weights to equal 100%. In the view of the staff, this MPPI is directly relevant to utility expenses by virtue of the fact that a wide variety of costs are included but inappropriate items are eliminated.

PG&E proposed a Company Specific Escalation Rate (CSER) as the means to escalate non-labor expenses for inflation. CSER is based on an examination of expenses as incurred by PG&E. Costs are isolated at a detailed level, which allows for the use of the appropriate detailed price indices forecasted by DRI to derive a composite index. Furthermore, since PG&E's actual expenses are used to develop CSER, PG&E argues that the weights attached to the various price indices reflect the utility's expenditure patterns.

Testimony for PG&E was presented by Dr. Tappan Munroe and for the staff by Mark R. Loy.

Munroe and Loy have a basic philosophical difference concerning the correct approach for determining non-labor escalation factors. Munroe's approach is to find a materials and services escalation methodology that gives PG&E-specific results. Loy, in contrast, seeks to have the Commission apply an economy or what he calls a utilitywide escalation approach to PG&E.

PG&E points out that the weightings in the staff's MPPI are subjective. There is no study supporting the applicability of these weightings to utility operations. Further, PG&E contends that staff witness Loy did not even attempt to justify them as being utility-specific.

According to PG&E, not only are the staff's MPPI indices and weightings subjective, but the methodology used to derive these weightings is theoretically suspect. PG&E notes that the staff project managers subjectively determined the appropriate items, as contained in 3-digit Bureau of Labor Statistics (BLS) categories, to be included in developing the MPPI from the universe of 3-digit BLS categories that make up the more inclusive 2-digit BLS categories. Then these selected 3-digit categories were escalated using the escalation factors that apply to the more inclusive 2-digit categories that include 3-digit categories that the staff previously excluded. According to PG&E, this approach makes no sense.

Staff argues that leaving aside for the moment the question of whether or not PG&E succeeded in achieving the accuracy it is aiming for, there are certain procedural problems with the CSER which outweigh all other factors. Essentially, staff contends that the CSER is so company-specific that only PG&E can develop and verify the calculations used to create it. According to the staff witness it would take $1\frac{1}{2}$ to $2\frac{1}{2}$ person-months to check and he therefore made no attempt to verify PG&E's study.

PG&E disagrees and contends that once the initial inputs to CSER are verified, the actual calculation can be done on a hand calculator in twenty minutes. According to PG&E, verification involves the review of accounting data broken down into cost elements, with which staff auditors are quite familiar.

We agree with PG&E that the concept of a company specific approach is certainly worth considering for test-year ratemaking; however, there are problems concerning verification.

We commend PG&E for the effort put into its study; however, for purposes of this proceeding, we are unable to accept PG&E's proposal because of the lack of verification. We strongly urge PG&E to work with staff on this matter well before its next NOI is filed. Advance arrangements should be made for staff auditors to examine the cost components of PG&E's study.

On the other hand, for purposes of this proceeding, we are also not prepared to adopt staff's MPPI methodology because of the arbitrariness of the weighting procedure.

The Commission is interested in a company specific approach if such an approach can be verified as sufficiently accurate to be an improvement over the utilitywide approach. If staff intends to continue with the latter, then it should submit a weighting procedure which will bear scrutiny. Possibly, staff could apply the PG&E initial inputs to its methods or derive its own based on actual recorded utility expenses.

We should also point out that the general rate case is not the ideal proceeding to resolve such technical differences. Because of the large amount of dollars associated with differences in escalation factors, $21.9 million in this instance, we urge the staff to sponsor a workshop so that existing staff-company disputes can be aired. Much remains to be done in this area and staff should, in spite of its workload, give priority to this important matter. This workshop should attempt to develop an agreed-upon methodology to deriving indices and weighting factors which reasonably reflect the nonlabor cost increases in PG&E's operations. Further, staff should explore whether such an approach could be applied consistently to other utilities.

During the course of the evidentiary hearing, the ALJ requested that the parties be prepared to choose one published index to be used for non-labor escalation rates for consideration by the Commission if a single fixed index was found to be desirable.

In response to the ALJ's request the staff recommended that the Wholesale Price Index for Industrial Commodities (WPI-IND) should be adopted for this purpose, just as it was in a recent decision for the Southern California Gas Company (SoCal). PG&E recommended two indices. Its preferred simplified index is a composite made up of 50% Consumer Price Index for Services (CPI-Services) and 50% Producer Price Index for Producers Finished Goods (WPISOP 3200). If forced to choose a single published index, PG&E would choose the WPISOP.

The table that follows presents the two staff and three PG&E proposals for non-labor escalation rates.

NON-LABOR ESCALATION FACTORS
Test Year 1984

	Staff		PG&E		
	MPPI*	WPI-IND	CSER*	Composite	WPI-SOP-3200
	%	%	%	%	%
1982	2.83	2.70	6.40	7.40	5.70
1983	1.77	1.20	3.30	3.30	3.10
1984	5.24	5.20	5.80	5.10	4.80
through 1984	10.13	9.34	16.30	16.60	14.21
1985	6.60	5.9	5.20	5.50	5.70
through 1985	16.74	15.79	22.30	23.02	20.72

*Respective recommendations of staff and PG&E.

The above non-labor escalation rates are calculated from the DRI September 1983 economic forecast, with the exception of the PG&E's CSER. CSER requires additional input from the DRI Cost Forecasting Service, which is generally released three weeks after the economic forecast. The values appearing under CSER reflect this additional September forecast.

Staff objects to the use of PG&E's composite index on the ground that it produces significantly higher escalation than is forecasted by all the other methods examined and is overly weighted with CPI related factors. The WPISOP 3200, PG&E's choice for a single index escalation rate, is less objectionable to the staff but, according to staff, still fails in comparison to the WPI-IND.

Staff argues that the single index chosen by PG&E, WPISOP 3200, does not include cost components for a number of raw materials which any major utility will in fact be purchasing, such as chemicals, rubber, plastic, lumber, wood, pulp, and paper. Staff notes that PG&E does buy a certain amount of these raw materials. Staff contends that its late-filed Exhibit 233, on non-labor escalation, shows that the components of the WPI-IND cover a much broader category of goods than the WPISOP 3200 shown by PG&E in its late-filed Exhibit 232.

Staff further argues that if in fact a single index is what the Commission desires, the breadth of scope of the WPI-IND is an advantage rather than a disadvantage. According to staff, while neither index is tailored to utility operations, the absence of unrelated cost elements is to be considered advantageous. Staff notes that in this respect, the staff's WPI-IND does contain fewer agricultural products cost elements than WPISOP 3200. Staff further notes that in the WPISOP 3200 agricultural machinery and equipment receives one of the highest weights at 6.2%. In contrast, agricultural machinery and equipment constitutes only .8% of the weighting in WPI-IND, the Wholesale Price Index recommended by the staff.

PG&E argues that the single index chosen by staff, the WPI-IND, has severe shortcomings. First of all, it includes all goods except agriculture and processed foods at all stages of processing, including raw materials, intermediate products, and final goods. (See

Exhibit 233.) As PG&E primarily purchases final goods, the WPI-IND does not properly reflect the utility's purchasing patterns. Furthermore, according to PG&E, WPI-IND includes no provisions for the services component of PG&E's non-labor costs; whereas, services account for approximately 50% of PG&E's non-labor costs. According to PG&E a single index which ignores 50% of the costs it is supposed to be escalating is fatally deficient.

Finally, PG&E notes that the goods included in the WPI-IND are weighted according to their production in the economy; therefore, PG&E argues they bear no similarity to the weightings of goods purchased by PG&E or any other utility.

We note PG&E's concerns about the WPI-IND but at the same time are not convinced PG&E's composite index or the WPISOP 3200 more accurately represents PG&E's operations.

We now address PG&E's argument that the nonlabor portion of its expenses contains a 50% labor component.

Our concern is that the staff's MPPI includes the Consumer Price Index (CPI) but with a weight of only 5%. While the CSER may be unduly complex, the utility's presentation (Exhibits 24, 111, and 121) has, in our opinion, demonstrated that PG&E's nonlabor expenditures do contain significant costs which are essentially labor in nature. For example, there are considerable contract and other direct services properly included in nonlabor costs. We will carefully consider this labor component in deciding upon an appropriate nonlabor escalation rate.

We conclude that the published indexes chosen by staff and PG&E, in response to the ALJ's request, have shortcomings. We cannot adopt the staff-proposed WPI-IND because this index would not accurately reflect PG&E's nonlabor costs. The WPI-IND is an overly broad index obviously including many types of costs unrelated to PG&E. For example,

Exhibit 233 shows that 15% of this index is for metals and metal products including iron ore and steel scrap, and that 19% is for fuels and related products. PG&E does not buy raw materials, and its energy costs are not included in the cost within this rate case.

On the other hand, PG&E's proposed WPISOP 3200 is too narrow. This index is a portion of the WPI-IND and represents capital equipment finished goods. PG&E also proposed a composite index made up of the WPISOP 3200 and the CPIU. This was done to reflect services which are a part of PG&E's nonlabor costs but are not included in any of the WPI's. However, as we pointed out, the WPISOP 3200 is too narrow an index and therefore the resultant composite is also unacceptable.

As a result of these considerations, we will adopt a composite index; however, we will not adopt PG&E's composite index for the reasons noted above. Rather, we adopt a composite of the staff's MPPI reweighted to include a 30% instead of 5% weight for the CPI-W. We will not use a 50% allocation because PG&E's contention has not been confirmed by the staff. In choosing the revised MPPI, we reject the two proposed WPI's because the WPISOP 3200 is lacking in many energy utility-related commodities, while the WPI-IND includes many commodities which are inappropriate. The CPIW reflects services and other labor-related expenses treated in nonlabor escalation. The adopted composite factor should reasonably reflect both the materials and services components within the utility's nonlabor expenses for the purposes of this proceeding.

Adopted Nonlabor Escalation Factors

Year	Factor
1982	3.4%
1983	2.2
1984	5.3
Compounded through 1984	11.3
1985	5.8
Compounded through 1985	17.7%

We will use WPI-IND for the historical escalation calculation in order to be consistent with past practice.

2. Preconstruction Costs

a. Overview

In its 1982 General Rate Case, PG&E was directed to review amounts held in Construction Work in Progress (CWIP) and Plant Held for Future Use (PHFU) accounts relating to discontinued projects no longer in the resource plan, and to provide appropriate recommendations for disposition or retention of such amounts in the next general rate proceeding. (D.93387, p. 37.) In response to this directive, PG&E filed Exhibit 16 "Feasibility Studies," in this proceeding.

PG&E contends that it is vital that the Commission reconsider its existing policies and develop a more equitable and forward looking means to share the risk of the precertification phase of energy project development in this uncertain planning environment. Therefore, PG&E submits for the Commission's consideration a Feasibility Studies proposal which, according to PG&E, is designed to assist it in meeting the challenges of the 1980's and 1990's in a rapidly changing energy environment.

PG&E defines Feasibility Studies to include those precertification and preconstruction activities necessary to determine utility project feasibility, including required investigations of reasonable alternatives, obtaining necessary regulatory approvals, and ultimately providing service to PG&E customers. These activities include utility efforts necessary to develop both PG&E-owned projects and third-party owned projects from which PG&E would purchase power.

Specifically, PG&E requests that the Commission change existing ratemaking policy and allow the expensing of preconstruction costs which are currently capitalized. PG&E claims that current policy subjects it to unacceptable levels of risk and is a disincentive to the pursuit of a flexible diverse resource plan. In addition to expense treatment on a prospective basis, PG&E requests that the policy change be retroactively applied, ~~thus allowing~~ a four-year write-off of all "booked" costs for project development for both abandoned and ongoing projects.

Staff argues that PG&E's proposal would result in a shift of risk for project development to the ratepayer whereas current policy provides for a sharing of this risk. Under staff's interpretation of Commission policy, the AFUDC portion of the project costs for which the shareholder is at risk provides management with an incentive to pursue the project efficiently, and to expedite it to completion or termination. The ratepayer is at risk for all other project costs without a voice in management or the opportunity to participate in profits.

The staff considers that sharing risk for project development is a vital ratemaking mechanism to encourage efficient utility operations. According to staff without such a mechanism utility management could not be held directly accountable for failed projects because of the prohibition against retroactive ratemaking.

Staff strongly disagrees with PG&E's claim of unacceptable risk and points to the various balancing account mechanisms, attrition allowances, and the Rate Case Processing Plan which have effectively reduced risk to California utilities. Staff contends that, contrary to PG&E's argument, the overall risk for utilities has declined in the last decade. Accordingly, staff sees no reason for change of present policy.

Staff also discounts PG&E's claim that utility risk creates a disincentive for management to pursue a flexible diverse resource plan. Staff points out that by placing the risk on shareholders, there is a direct incentive to develop projects which have less financial risk. Staff observes that in a financial climate of high inflation and interest rates, PG&E has succeeded in adding a variety of less capital intensive alternative generation projects to its resource mix.

With respect to abandoned projects, the staff recommends disallowance of AFUDC, and a four-year amortization of direct costs with no return during the amortization period. Staff submits that this treatment is consistent with current policy and represents an equitable sharing of risks and costs between ratepayer and stockholder, and will not have a material impact on the utility's financial position.

b. <u>Feasibility Studies</u>

PG&E requests the following ratemaking treatment of feasibility study expenditures:

1. All 1984-1985 Feasibility Study expenditures which would previously have been accumulated for possible capitalization would be expensed for ratemaking purposes.

2. All pre-1984 CWIP balances associated with Feasibility Studies for projects represented in PG&E's Long-Term Plan would be placed in rate-base pending their cost recovery by amortization over four years.

3. All pre-1984 CWIP balances associated with Feasibility Studies for suspended projects would be treated as in Item 2, except that the unamortized balances would not be included in rate base.

Staff recommends:

1. 1984-85 Feasibility Study expenditures should not be expensed for ratemaking purposes, but should continue to be carried on PG&E's

books as a deferred debit pending ultimate construction or abandonment.

2. Pre-1984 CWIP balances associated with Feasibility Studies for projects represented in PG&E's Long-Term Plan should be excluded from rate base. Such costs should be deferred as recommended in 1. above, pending ultimate construction or abandonment.

3. Pre-1984 CWIP balances associated with Feasibility Studies for suspended and/or abandonment projects would be amortized over a four-year period reduced by the related AFUDC capitalized through December 31, 1983.

Staff witness William D. Thompson presented an alternative ratemaking approach for PG&E's abandoned project costs. This alternative was generated as a result of Thompson's participation in PG&E A.82-12-004 which involves the possible abandonment costs associated with the utility's LNG project at Point Conception.

Thompson states that the potential loss to PG&E from the LNG project alone is $104 million. In Exhibit 220, Thompson estimates that the combined potential total losses from the abandonments, which are the subject of this rate case and the LNG case, would be approximately $155 million or, roughly, 20% of the utility's projected 1984 stockholder earnings. Thompson expressed concern that losses of that magnitude could affect PG&E's financial position and increase its cost of capital.

Thompson's alternative recommendation is a response to the possibility of an increase in cost of capital which seeks to mitigate the first year writeoff of losses from cancelled projects without incurring significant additional expense for ratepayers. This is achieved by permitting the utility to recover a portion of the AFUDC involved but at the same time extending the amortization period from four years, as recommended in staff's original proposal, to twelve years. A comparison of the net present value costs to both ratepayers and stockholders from this alternative proposal can be seen in Exhibit 224.

While we find staff witness Thompson's alternative interesting, we choose not to adopt his approach in this proceeding. We will consider elsewhere the effect of the LNG case on investor perception of the utility's risk.

Listed below is a summary of the major suspended projects which PG&E seeks to amortize in this proceeding, together with recorded costs incurred as of December 31, 1981:

Suspended Projects
As of 12-31-81

Project Name	Year Suspended or Abandoned	CWIP Balance excluding AFUDC (000)	AFUDC Balance (000)	Total CWIP Including AFUDC (000)
Mendocino (nuclear)	1973	$13,579	$ 6,536	$ 20,115
Stanislaus (nuclear)	1978	10,955	5,345	16,300
Potrero (gas)	1980	16,079	3,663	19,742
Pittsburg 8 & 9 (oil)	1980	4,645	1,509	6,154
Other Projects less than $5 million*		15,428	5,657	21,085
Montezuma (coal)**	1981	14,305	4,257	18,562
Totals		$74,991	$26,967	$101,958

(Exhibit 60, page 24.)

* Includes Allen-Warner Valley coal project and Moss Landing Project.

** This project is considered separately in the next section.

PG&E estimates additional AFUDC capitalized on the suspended projects during 1982 and 1983 of $21,456,000, bringing the total balance of suspended projects to $123,414,000 as of December 31, 1983. Notably almost one-half of the requested AFUDC relates to 1982 and 1983 accruals.

It should also be noted that although PG&E has characterized many of these projects as suspended, they are essentially the same as cancelled projects and should be treated as such. A complete list of these suspended projects is contained in PG&E Exhibit 16, p. 2-16.

Staff witness Thomas R. Pulsifer, the Financial Examiner responsible for the staff audit reviewed in detail suspended project costs over $5 million. He concluded that "PG&E demonstrated a reasonable need for the projects undertaken, based upon information available at the time, and that direct expenditures were suspended at the appropriate time", and recommended that all direct costs for these suspended projects be recovered through amortization.

The pre-1984 Plant Held for Future Use (PHFU) balances associated with sites purchased for certain suspended projects would be treated by PG&E as follows:

1. PG&E would offer for sale the Mendocino and South Moss Landing sites and request rate treatment for the net gain or loss in the next appropriate rate proceeding.
2. PG&E would retain the sites for Montezuma and Pittsburg Units 8 and 9 for future use and continue to hold their costs in PHFU. (Exhibit 16, p. 1-8.)

The PHFU balances are set forth below:

As of December 31, 1981

Mendocino	$1,305,471
South Moss Landing	2,110,471
Montezuma	899,598
Pittsburg 8 & 9	2,528,195

(Exhibit 16)

The staff rate base witness objected to inclusion of the Montezuma and Mendocino sites in PHFU because of the absence of a specific and definite plan for their use. In the case of Mendocino, since PG&E contemplates a sale of the site, it obviously is no longer considered useful.

The staff accounting witness further objected to the inclusion of the South Moss Landing site because of PG&E's contemplated sale.

PG&E stipulated only to the exclusions from PHFU made by the staff rate base witness. These exclusions will be adopted. In addition, we shall remove the South Moss Landing site from PHFU for the same reason that the Mendocino site is removed. In the event of a sale of either site we will require PG&E to report in its next appropriate rate case any gains or losses realized.

PG&E plans no specific and definite use for the Pittsburg 8 and 9 site. This site has been in PHFU since 1973. Because PG&E has failed to justify continued inclusion of this site in PHFU, we shall remove it from that account.

c. Prospective Recovery of Feasibility Study Costs

We will address PG&E's request to change current policy to allow expense treatment of preconstruction costs on a prospective basis.

There are two striking features to PG&E's proposal, which we cannot accept. First, the proposal would require the Commission to review the reasonableness of these expenditures on an estimated basis before the expenditures are incurred, thus giving little or no opportunity for subsequent review as there is presently. Second, by receiving financing for such expenses up front, there will be no risk of abandonment to the shareholders. The entire risk will be borne by ratepayers. As a result, PG&E would have little or no incentive to fund only those proposed projects which have a reasonable likelihood of success.

In D.82-12-055 dated December 13, 1982, we considered and rejected a similar proposal by Edison. For the reasons discussed in that decision we reject PG&E's request. In doing so, we should observe that new projects have now become less capital intensive and smaller than they were in the past under current allocations of risk. Consequently, the utility's exposure to large abandoned project costs is now considerably less.

PG&E also requests amortization of pre-1984 capitalized preconstruction costs for long-term projects which are on-going. Again, we are not willing to shift the entire risk of possible abandonment of these projects to the ratepayers. We deny this request as well.

d. Recovery of Past Feasibility Study Costs

We will now address PG&E's request to recover preconstruction costs of $60.8 million for 26 suspended or abandoned projects.[4] The Montezuma project will be discussed separately in the next section.

We begin by analyzing these projects under used and useful principles, long followed by our Commission. Under these principles, ratepayers are required to bear only the reasonable costs of those projects which provide direct and ongoing benefits, or are used and useful in providing adequate and reasonable service, to the ratepayers. Those projects which never reach fruition by definition fail to be used and useful to the ratepayers. As a result the costs incurred in determining the feasibility of a given project which is later abandoned are borne by the shareholders.

By our requiring shareholders to absorb feasibility study costs, management has an economic incentive to select only those projects that are reasonably likely to succeed. Importantly, it is management alone that decides initially which projects to pursue and which projects to abandon.

[4] PG&E has characterized a number of projects as "suspended" when they in fact are abandoned. In the future we expect PG&E to define clearly the status of each project for which it seeks cost recovery.

Applying used and useful principles to the 26 abandoned projects for which PG&E requests cost recovery, we would be compelled to deny PG&E's request. However, we have granted limited exceptions to these principles on a case-by-case basis, where circumstances warrant.

A review of the exceptional cases is presented in D.92497 dated December 5, 1980. In these abandoned project cases we allocated the direct feasibility costs to ratepayers and AFUDC costs to shareholders. The costs borne by ratepayers were then amortized over a period of years. We have allowed the utility to rate-base a portion of the unamortized costs only when residual value or potential benefits were likely to accrue to the ratepayers. Otherwise we considered such treatment as an inappropriate shifting of risk to the ratepayers (D.92497, WESCO project).

We now determine whether an exception to traditional ratemaking treatment is warranted for the 26 projects presented in this case. PG&E not only requests recovery of direct feasibility study costs but also AFUDC.

PG&E has made our task difficult by combining the costs of all 26 projects. Moreover, the cost of each project is inflated by PG&E's continued accrual of AFUDC on projects after they were deemed abandoned by the utility. As pointed out by staff, such accruals of AFUDC, totaling over $11 million alone in 1983, are improper under the Uniform System of Accounts.

Also, at least $31 million of the direct costs of $60.6 million are for projects which were abandoned in 1978 or earlier. For example, about $14 million relates to the Mendocino nuclear project abandoned ten years ago, and about $11 million relates to the Stanislaus nuclear project, abandoned about five years ago. We fail to understand why PG&E did not seek recovery of these costs when it had ample opportunity to do so in at least two prior general rate cases. We are concerned because this practice has led to two undesirable results: (1) it has greatly increased the magnitude of costs claimed for recovery from ratepayers, making it more difficult for ratepayers to absorb these costs should we deem it reasonable for them to do so; and (2) it has greatly diminished the ability of our staff to review carefully the reasonableness of costs for each project. Moreover, by not seeking timely recovery of its costs, PG&E may have incurred increased financing costs which would have indirectly been borne by its ratepayers.

We place PG&E on notice that we will not condone this practice in the future. Henceforth, we will not entertain requests for abandoned project costs unless such requests are made in the next general rate proceeding immediately following abandonment.

Both our staff and PG&E assume that we will automatically permit recovery of the direct feasibility costs for these projects, based on the prior cases granting exceptions to the used and useful principles. Again we emphasize that allowance of recovery is the exception not the rule.

After careful consideration we will allow PG&E to recover the costs of feasibility studies for the 26 projects as exceptions to traditional ratemaking principles. Our conclusion is based on two important factors which together justify the exceptions.

First, we are influenced by the fact that the period during which many of these projects were begun and later abandoned was one of dramatic and unanticipated change. Many of these projects were large, baseload plants, most notably coal and nuclear, which were planned in the late sixties and early seventies during a period of stability and certainty. Characteristic of this period were increasing growth in customer demand, ready access by utilities to financial markets, and state and federal policy favoring the type of projects being planned.

During the middle and late seventies, great regulatory uncertainty and economic volatility replaced the predictable and secure environment to which the utilities had grown accustomed. Specifically, the combination of lower growth in customer demand, capital constraints, uncertain fuel supply, and more stringent environmental and legislative requirements led utilities to reconsider the viability of traditional projects. Abandonments began to occur.

Because of the extraordinary and unpredictable changes in circumstances which occurred during this period, we have questioned whether shareholders should bear the entire cost of these abandoned projects.

The second factor which influences us is the magnitude of the abandoned project costs sought by PG&E. As discussed above a substantial portion of the accumulated direct costs related to projects abandoned in 1978 or earlier could have been prevented by timely requests for recovery. Were we to base our decision on the magnitude of these costs, we would give much less weight to this factor. However, over $25 million in direct costs are for projects abandoned in 1980 or later. We are reluctant to require PG&E to absorb these costs in the absence of a record indicating the finanical impact that these costs would have on PG&E.

Accordingly, these two factors in combination have persuaded us that a sharing of the abandoned project costs between ratepayers and shareholders is fair and reasonable.

We observe that today PG&E is actively pursuing the development of resources which are favored by economic and regulatory conditions. We therefore do not expect either the number or type of abandonments that have occurred in the past to continue in the future.

While granting an exception to allow recovery of direct feasibility study costs, we will continue our policy of not allowing the recovery of carrying costs. We do so for two reasons. First, we believe that shareholders should continue to bear a portion of the risk of abandoned projects under all circumstances for the reasons set forth in our discussion of used and useful principles. Second, and more specific to these projects, we find that PG&E improperly accrued AFUDC on these projects after they were abandoned.

We will adopt staff's recommendation to amortize over four years the direct preconstruction costs of the 26 projects. We will not rate-base the unamortized costs for the reason that none of these projects have any residual value to the ratepayers.

We adopt the following accounting treatment for feasibility studies:

1. All expenditures for preliminary surveys, plans, investigations, etc. made for the purpose of determining the feasibility of ongoing utility projects shall be recorded in Account No. 183.

2. For feasibility studies related to projects which have been discontinued, the associated costs should be transferred initially to Account No. 186, pending resolution of the ultimate disposition of such costs in the next available general rate proceeding.

3. No AFUDC should be capitalized after abandonment of a project. For those ongoing projects which reach the construction stage, AFUDC may be capitalized in Account No. 107.

We will not adopt staff witness' recommendation that no AFUDC should be capitalized during the preconstuction stage. We believe that the utility should continue to be allowed to accrue AFUDC on preconstruction costs. Such accruals properly compensate shareholders for the risks assumed if the project becomes operative.

3. Montezuma Project

a. Overview

In D.82-12-121, dated December 30, 1982, which was followed by D.83-06-064 dated June 15, 1983, the Commission considered the appropriate ratemaking treatment to be given to PG&E's after-tax gain of about $94.4 million from the sale of Utah coal reserves purchased for use in the Montezuma power plant project. A complete background of this project is contained in D.82-12-121.

The power plant project was effectively abandoned in September 1981 when PG&E sought bids for the sale of the coal properties. On December 31, 1981 PG&E accepted a bid of $171.2 million from Sunedco. Escrow was opened on March 4, 1982 to complete closing requirements for the transaction.

On May 13, 1982 escrow was closed and PG&E received a principal amount of about $161.2 million plus cumulative interest earned on the $171.2 million since March 4. The remaining $10 million plus interest remained in escrow until May 31, 1983 to satisfy any outstanding claims. Thereafter, the proceeds were distributed to PG&E.

In D.82-12-121 we distinguished between the after-tax gain on that portion of the coal properties investment that was placed in rate base and the gain on that portion which was not. For that portion included in rate base we stated, "[T]here is no question that the amount of the gain allocated to the rate base property should be returned to ratepayers." (mimeo. p. 24.) This amount totaled $55.3 million. However, we deferred the question of how to allocate the gain on the non-rate base portion to this proceeding. In doing so we stated,

> "We also find that risk analysis should be the major consideration underlying the allocation of the gain from the sale." (mimeo. p. 3.)

and

"The risk allocation question applies only to the portion of the gain that is allocated to the non-rate base property" (Emphasis added, mimeo. p. 24.)

and

"...our decision leads us to conclude that the relative risks in this case should be properly evaluated in terms of the risks involved in undertaking the entire Montezuma project." (mimeo. p. 24.)

The after-tax gain from the sale of the coal reserves which still remains is $37.9 million. PG&E has also incurred $14.3 million in costs for feasibility studies undertaken for this project and has accrued from $4.2 million to $8.1 million in AFUDC, depending on which date of AFUDC cut-off is used. Specifically, there are two issues to be resolved:

1. The allocation of the remaining gain from the sale of the Montezuma coal reserves between ratepayers and shareholders in the amount of $37,937,000 after taxes.
2. The allocation of the Montezuma feasibility studies cost between ratepayers and shareholders in the amount of $14.3 million to $22.4 million.

b. Positions

PG&E did not provide direct testimony on these issues, but in its brief argues that the shareholders should receive all the remaining gain from the above coal sale. During cross-examination, however, PG&E witness Gallavan indicated it would be acceptable to PG&E to assume the feasibility study expenses in return for all of the unallocated gain from the coal properties.

PG&E argues that through its management efforts, PG&E transformed a $32 million investment into an asset which commanded a price five times that. PG&E submits that equity and basic regulatory principles require that the shareholders receive a fair return from this commendably successful venture. We should explain that the $32 million is a direct cost and does not include any AFUDC. It consists of a $14 million ratebased component and an $18 million non-ratebased component. According to PG&E, the utility should receive the remaining gain of $37.9 million because, under the theory contained in D.82-12-121 where ratepayers received the entire profit related to that portion of the coal property that was found to be in rate base, the $37.9 million profit from that portion of the investment which was never placed in rate base should flow solely to the shareholders.

In addition, PG&E argues in its brief that because the Commission has directed that the Utah Coal sale and the suspended Montezuma coal-fired power plant be treated as one "entire Montezuma Project", PG&E should recover its total investment in the Montezuma plant, which includes $14.3 million of direct costs and $8.1 million of AFUDC accrued through December 31, 1983.

Different methodologies for distributing the remaining gain and the feasibility study costs were entered into the record by two staff witnesses, Thomas Pulsifer of the Revenue Requirements Division, and Catherine Waddell of the Commission's Policy and Planning Division.

Staff witness Pulsifer submits that he kept in mind that the Commission expected the parties to evaluate the relative risks between ratepayers and shareholders as to the coal reserves in terms of "the risks involved in undertaking the entire Montezuma project." (D.82-12-121, p.24).

Pulsifer notes that he commenced his analysis from the premise laid out by the Commission in D.82-12-121. That is, according to Pulsifer, the Commission clearly indicated that, "risk analysis should be the major consideration underlying the allocation of gain (or loss) between shareholders and ratepayers." (D.82-12-121, p.23). In order to define this risk allocation, Pulsifer referred to the Commission's allocation of risk between shareholder and ratepayer with respect to amortization of the direct cost of certain abandoned projects. (Ex. 60, pp. 16-17, Tr. 9987). According to Pulsifer, current Commission policy requires the utilities' investors to bear the risk and loss related to carrying costs of the investment, or the AFDC which has accrued thereon; correspondingly, ratepayers would be responsible for absorbing the direct costs of any such abandonment. Therefore, on the basis of apportioning the direct cost and AFDC related to the total cost of feasibility studies, Pulsifer allocates risk as set forth below:

As of December 31, 1981

Item	%	($000's)	Risk Allocated To:
AFDC	23	$ 4,257	Investor
Direct	77	14,305	Ratepayer
Total	100	$18,562	

By applying the risk sharing allocations associated with the feasibility studies loss as calculated above to the coal reserve gain, Pulsifer derived the following allocation of gain:

Item	% Allocation	$000's
Ratepayer Share	77	29,211
Investor Share	23	8,726
Total		$37,937

Pulsifer notes that D.82-12-121 specifically directed that "the risk allocation question applies only to the portion of the gain that is allocated to the non-rate base property. There is no question that the amount of gain allocated to the rate base property should be returned to the ratepayers."

Therefore, Pulsifer recommends that the remaining gain for the non-rate base portion be allocated 77% to ratepayers and 23% to investors. To be consistent with the treatment used by the Commission for feasibility studies, Pulsifer recommends that the gain assigned to ratepayers be amortized over four years with no recovery of interest during the amortization period.

PG&E argues that under Pulsifer's approach, the longer AFUDC is accrued, the more the shareholder is at risk, and the greater should the shareholder's portion of the gain be. Thus, a key decision is the date selected to relate direct costs to AFUDC.

PG&E submits that if Pulsifer's methodology is adopted, the correct AFUDC cut-off date to use is December 31, 1983. It is on this date when, following a decision in this proceeding, PG&E will actualy cease accrual of AFUDC on the Montezuma Project and will abandon the project for accounting purposes. In its brief, PG&E shows the significance of the choice of the AFUDC cut-off date to the allocation of gain. According to PG&E there is no rational rationship between the direct cost/AFDC split on the day picked by Pulsifer and any equitable distribution of the remaining gain. Likewise, according to PG&E there is no logical relationship between the risk of PG&E's undertaking construction of an in-state electric generation plant--the utility's traditional business--and a subsidiary's development of an out-of-state coal reserve.

We now turn to staff witness Catherine Waddell's presentation set forth in Exhibit 59.

The essence of her approach is that the entire Montezuma project should be considered as one unified investment. That includes the engineering and environmental studies performed pursuant to obtaining permits to construct the Montezuma coal-fired power plant as well as the coal properties and development expenses associated with PG&E's obtaining a fuel source for the power plant. Also, for clarification, that covers elements of cost such as the rate-based coal property which was the subject of D.82-12-121, and the refund of $55,331,000 to the ratepayers. Waddell emphasizes that the Commission clearly states that the gain should be allocated "in terms of the risks involved in undertaking the entire Montezuma project" (D.82-12-121, p. 24, emphasis added), of which the Utah coal investments were only a portion.

The basic focus of Waddell's exhibit is to determine what is an appropriate or fair rate of return on what is essentially a profitable utility investment. To do this, Waddell undertakes a net present value analysis to determine what a competitive return on the investment would be. (Exhibit 59, p.4.) However, such an analysis cannot be performed without selection of a discount rate which reflects the fundamental or underlying risk of the project. Also, as there are two components of this project, the construction of the utility power plant and the purchase of energy reserves in the form of coal, there are two different levels of risk.

Accordingly, Waddell considers two different levels of risk and two different discount rates, one for average utility operations and another for investment in energy raw materials. (Exhibit 59, p.7.) She then performs her net present value analysis using both discount rates and arrives at two figures for PG&E's final profit on the investment. After allowing for recovery of the book value of the investment, including the feasibility studies, Waddell determines that the gain to the utility should be between $29,800,000 and $15,036,000. (Exhibit 59, p.12.) In order to arrive at a single recommendation, Waddell chooses the median value of $22,422,000 as the final gain for the utility over and above recovery of book value and feasibility study costs.

The bottom line of Waddell's recommendation is that shareholders would receive $68,057,000 which includes $46.9 million for recovering the book value of the utility's investment in the project, including feasibility studies; the ratepayers would receive $56,625,000 of which $55,331,000 has already been refunded to them through D.82-12-121; $2,350,000 would remain with PG&E, subject to FERC jurisdiction; and PG&E's request to amortize the feasibility studies costs of $18,562,000 would be eliminated from the rate case, as it has been recovered in the shareholder recovery mentioned above.

TURN disagrees with staff witness Waddell's approach for the reason that she reflected all of PG&E's expenditures on the Montezuma plant and the Utah coal properties, without excluding the portion that was included in rate base. As an offset, she then added positive cash flows equal to the authorized return on the rate-based portion. According to TURN, this mixture of authorized returns and real discount rates seems questionable at best. TURN, however, overlooks Waddell's testimony that if the rate based portion and related cash flows were removed from her analysis, the end result would essentially be the same.

According to TURN a peculiar aspect of Waddell's approach is that her resulting allocation to shareholders is independent of the size of the profit realized on the coal sale. Therefore, TURN argues that if PG&E had gained $25 million more or less, she would recommend the same dollar amount for shareholders. TURN submits that essentially Waddell's calculation does nothing more than estimate a fair rate of return on the utility's investments, using a different approach to rate of return than this Commission has adopted.

TURN argues that given this fixed rate of return approach and the inclusion of the rate-based properties, Waddell's calculation could easily have resulted in ratepayers owing PG&E money.

Staff counsel argues that the analysis of staff witness Waddell does not conform to D.82-12-121 because it does not allocate between the ratepayers and shareholders the remaining gain and expenses of the project on the basis of the risk inherent in the entire project. Rather, staff counsel contends that Waddell examined only the risks and returns which were due the utility under her theoretical approach, and did not consider in the same fashion the risks which the ratepayers had undertaken with respect to this project.

According to staff counsel, the analysis of Waddell does not appear to take into account the fact that utility's risk would be considerably less than that experienced in either the utility industry or the energy raw material industry with respect to that portion of the investment which was already contained in rate base, nor that in recent Commission decisions the utility expenses for feasibility studies were essentially undertaken with only the risk of the carrying costs at issue for shareholders. Therefore, staff counsel recommends that the approach of staff witness Pulsifer be adopted by the Commission in allocating the remaining gain and expenses from this project to the investors and the ratepayers.

PG&E argues that if the Commission does not accept its proposal that shareholders receive all the remaining non-rate base gain from the coal sale, it should alternatively adopt staff witness Waddell's recommendation.

c. Discussion

We first discuss the staff proposals. The proposal offered by Waddell attempts to capture the carrying costs, or return, that shareholders would have earned on the entire project. We find conceptual merit in this approach. However, the proposal views the risks to the utility and the ratepayer not only for the non-rate base portion of the project but also for the rate base portion. Since we have already disposed of the allocation of the gain for the rate base portion, we do not deem it appropriate to examine that portion once again. We are mindful of TURN's argument that our review of the entire project under Waddell's methodology could lead to ratepayers having to refund a portion of the gain already received. Such a result is undesirable.

In his proposal Pulsifer allocates the gain for the non-rate base portion of the coal property in the same proportion by which the loss is allocated. Conceptually, there is also some merit to Pulsifer's proposal. If ratepayers realize the losses on the direct investment in failed projects, they should also receive any gains. Similarly, if shareholders bear the loss of carrying costs on failed projects they ought to recoup such costs from any gains received.

While Pulsifer's proposal recognizes that PG&E's shareholders should earn a portion of the gain on the sale of the coal reserves, the percentage portion he allocates to shareholders appears arbitrary. We fail to understand why the date upon which AFUDC stopped accruing on the feasibility costs should dictate that portion of the carrying costs that shareholders would receive on the coal sale gain. In our view that date is not relevant for apportioning the proceeds from the coal sales gain.

We now turn to our disposition of the project benefits and costs.

Unlike other abandoned projects which usually result in a net loss to the utility and its ratepayers, the Montezuma project is unique in that it resulted in a net gain. We must therefore determine under ratemaking policy principles how to apportion the gain between PG&E and its ratepayers.

To begin, we will clarify our intent in D.82-12-121 in determining how to allocate both the gains and the losses between ratepayers and shareholders from this project. In that decision we applied a risk analysis but only to that portion of the Montezuma coal properties which were placed in rate base. We concluded that since ratepayers assumed the entire risk of the rate-based properties, they should realize the entire gain. Such treatment implicitly recognized that the shareholders have been made completely whole through recoupment of their original investment plus a return on the rate-based properties.

An important feature of this ratemaking treatment was that ratepayers received all of the appreciated value on the rate-based properties. This treatment was consistent with our decision regarding distribution of the gain on assets of the So Cal Gas Standard Oil of Ohio (SOHIO) project. In that decision we found that the utility's investors should be foreclosed from any claim to an asset's appreciated value when they have been insulated against the risk of loss of their investment (84 PUC at 420). Our finding was based on the federal district court decision of Democratic Central Comm. v. Washington Metropolitan Area Transit Comm's, 485 F. 2d 786 (D.C. Cir. 1973), cert. den., 415 U.S. 935, which held that ratepayers have a legal right to share in the appreciation in the market value of assets which have been used in a public utility's regulated enterprise. Where ratepayers have the financial burden associated with such assets and investors have been shielded from the risk of loss of their investment, the appreciation in market value over the net book value must be credited to ratepayers in the ratemaking process. (Id. at 806-11).

In the SOHIO decision we identified three principles to guide us in reaching our decision:

1. The right to capital gains on utility assets is tied to the risk of capital losses.
2. Whoever bears the financial burden of a particular utility activity should also reap the benefit resulting therefrom.
3. Consumers become entitled to appreciation in value of operating utility assets when they have discharged the burden of preserving the financial integrity of the stake which investors have in such assets.

We have cited portions of the SOHIO decision because we believe that these principles should guide our determination of how to allocate the gains and losses from the non-rate-based properties and the feasibility studies of the Montezuma project. As a further guide we shall consider the application of used and useful ratemaking principles.

Applying the three principles discussed above to the non-rate-based properties, we find that PG&E's shareholders should realize the entire gain. By not placing these properties in rate base, the shareholders assumed the entire risk of loss or damage to their investment. In return, we find it equitable for shareholders to capture any appreciated value.

The application of used and useful principles leads us to the same result. Under these principles, abandoned projects are not included in rate base because by definition they never become useful to the utility in performing its regulated services for the benefit of ratepayers. As a result the utility's shareholders bear the entire risk of loss from abandonments. Conversely, they should reap the entire gain.

We next dispose of the feasibility study costs associated with the Montezuma project. Like the non-rate-based coal properties these costs have never been capitalized and placed in rate base. We reaffirm our intent in D.82-12-121 that the costs of feasibility studies should be considered with the coal assets as part of the entire Montezuma project. Accordingly, these costs should be reflected in calculating the net gain to shareholders.

In a prior section of this decision we required ratepayers to absorb the direct costs of feasibility studies for abandoned projects but only as exceptions to the traditional used and useful concepts. The exceptions were justified for two reasons. We first considered the dramatic changes in the economic and regulatory climate from the time the projects were begun to the time the projects were abandoned. Secondly, we considered the magnitude of costs which shareholders might have to absorb at one time. We therefore found it equitable to allocate the losses between ratepayers and shareholders.

For the Montezuma project, only the first factor is present; this factor is entirely offset by the further gain, and favorable financial impact, which shareholders will realize on the coal properties. Accordingly, we do not find that an exception to the used and useful principles is warranted in this case.

In sum, we conclude that PG&E's shareholders should receive the entire gain of $ 37.9 million realized from the sale of the non-rate-based coal properties and should absorb the direct feasibility study costs of $14.3 million, for a net gain of $23.6 million. We find this treatment equitable to both ratepayers and shareholders and consistent with prior decisions.

4. Research Development And Demonstration (RD&D)

a. Test Year Ratemaking Treatment

This section discusses the RD&D policy issues raised in this proceeding. PG&E's test year RD&D programs, which are described in PG&E Exhibit 17 and staff Exhibit 149, are discussed elsewhere in this opinion.

The ratemaking treatment for RD&D was initially set forth by the Commission as follows:

> "Cost Recovery Practice
>
> The staff proposes that the utilities include discussion in their filings describing how expenditures are to be recovered for each RD&D program or project. The staff recommends that the basic ratemaking policy for recovery of RD&D expenditures should continue to be the expensing of RD&D in the various accounts in conformance with the FERC Uniform System of Accounts. RD&D expenditures resulting in the construction of tangible plant would be capitalized and recovered through depreciation and return on investment when such plant becomes used and useful.

Exceptions should be handled on a case-by-case basis.

"All parties agreed that the expensing of RD&D projects is preferred, and that the propriety of capitalizing individual projects or alternative treatment would be addressed on a case-by-case basis." (D.82-12-005 dated December 1, 1982. These are the last two paragraphs at page 14.)

Next, the Commission modified D.82-12-005 as follows:

"The following language is added to the last paragraph at page 14:

'Edison recommended that the 'used and useful' concept should not be applied to RD&D tangible plant but that the Commission provide for recovery of RD&D plant in a manner consistent with the FERC Uniform System of Accounts. The utility contends that the benefit which is provided to ratepayers by virtue of RD&D projects is knowledge, which may be provided at any stage of an RD&D project, no matter what direct service ratepayers may be receiving from the project and that a project may be successful, in that a wealth of information may be generated, but the project may never be "used and useful" as the term has traditionally been utilized. PG&E, in its comments, agreed that capitalization of all tangible plant is not appropriate, as much RD&D plant never becomes "used and useful" but proposed a flexible approach for cost-recovery rather than strict conformance with the FERC Uniform System of Accounts.

'We will adopt the staff proposal: RD&D expenditures shall be capitalized and recovered through depreciation and return on investment when such plant becomes used and useful. Exceptions shall be handled on a case-by-case basis. The handling of exceptions in this manner should remedy the potential problems raised by Edison.'" (D.83-03-021 dated March 2, 1983, emphasis added.)

Turning to the specific issue in this proceeding, with the exception of two programs, staff agrees with PG&E's position that the remaining test year RD&D programs receive expense treatment. The disagreement concerns two programs for which staff recommends capitalization: (1) the Cheng Cycle Gas Turbine Project for $1.5 million in 1984 and $3.9 million in 1985 and (2) the Carrisa Plains Solar Project for $5.6 million in 1984 and $8.3 million in 1985. Both are stated in 1981 dollars.

The major point of contention is the appropriate accounting treatment. The controversy surrounds interpretation of language contained at page 14 and at Appendix A, page 6 in D.82-12-055 dated December 1, 1982, as follows:

> "RD&D expenditures resulting in the construction of tangible plant would be capitalized and recovered through depreciation and return on investment when such plant becomes used and useful. Exceptions should be handled on a case-by-case basis."

We will clarify this language.

We interpret the above language to mean that, if there is no reasonable prospect at the outset that a demonstration project involving "tangible plant" will become "used and useful" by becoming part of the utility's electric or gas operations, then the expenditures should receive expense treatment for ratemaking purposes. Therefore, if the end result is knowledge, or does not involve tangible plant, the program costs should receive expense treatment. Otherwise, the cost should be capitalized.

PG&E emphasizes that the Cheng Cycle Project will never be a reliable source of generation. Almost as soon as it is built, it will be dismantled to analyze the impacts of operation on the turbine's internal structure. During its brief life, it will produce barely enough power to run itself, will never be hooked into PG&E's grid to provide power for customers, and therefore will never be used and useful in the conventional sense. It may not even work. According to PG&E this risk, inherent in the nature of all demonstration projects, is at the heart of PG&E's request for expense treatment.

Staff argues that tangible plant will result from the Cheng Cycle Project, even if it exists only for a limited period of time. In staff's view the gas turbine which comprises the majority of the project is equipment which has the capability of becoming reliable generation plant. Accordingly, the plant should be capitalized. Furthermore, staff recommends that amortization of costs begin during the period when the project will be used and useful. Staff notes that this is not at the commencement of the project or the early design stage of the project. Rather, amortization would occur during the demonstration phase when valuable knowledge will be gained. According to staff, permitting amortization to begin in the second year of the two-year project would coincide with the benefits to be derived from the demonstration of the project.

Staff witness Ramesh Joshi recommended that the operating and maintenance expenses associated with the Cheng Cycle Turbine Project in 1985 ($250,000) be expensed, but that the materials, engineering, and design costs ($1.5 million in 1984; $2.5 million in 1985) be capitalized and amortized. If the project generates electricity, the amortization would be over the experimental period. If it does not generate electricity, it would be treated as abandoned and the expenditures would be amortized over two years, following the end of the demonstration. The project would then be subject to review to decide the appropriate amount of recovery.

We note that amortizing the expenditures for materials and engineering over the two years of the experiment (1985-86) would be tantamount to expense treatment for the Cheng Cycle demonstration. Since the project is not designed from the outset to become (even if successful) part of the utilities operations, we do not consider the expenses "tangible plant" for purposes of RD&D ratemaking.

We recognize, however, that the major portion of costs related to this project is comprised of equipment, specifically a gas turbine, which may later be used as part of reliable generation plant or even sold at the end of this project. If that equipment is sold, we direct PG&E to inform this Commission as to the amount of sale proceeds. That amount will be deducted from PG&E's subsequent rate case revenue requirement. PG&E is also directed to notify the Commission if and when any of the equipment is used, subsequent to completion of the RD&D project, in conjunction with a commercial facility. These equipment costs must be explicitly excluded from any CWIP account or ultimately, rate base associated with the commercial facility.

We turn now to the Carrisa Plains Solar Power Project. As discussed above, this project will require $5.6 million in 1984 and $8.3 million in 1985, all stated in 1981 dollars. This project involves a 30 megawatt generating facility similar to Edison's solar 100 project, but utilizing a different array of heliostats and a different heat transfer fluid. The project has additional unique characteristics in that PG&E will have no ownership interest in the project for its total $13.9 million investment, yet PG&E's 10% investment in the project is considered by all parties to be essential. In other words, if PG&E does not go forward, the project will not go forward. What PG&E will obtain for its investment is the technology through patent rights which arises from the demonstration project.

Our concern, at this time, is that there is great uncertainty that the Carrisa Plains Project will go forward either in the test period or at any other time. Importantly, no signed contracts among the parties have been entered into. Moreover, we are not convinced that any specific benefits accrue to PG&E's ratepayers through PG&E's $13.9 million investment. PG&E has no ownership interest in this project, nor is there any basis to conclude that PG&E will ever be able to use this technology if the project is successful. Furthermore, we are concerned that, in the absence of any ownership interest, PG&E is effectively providing seed money funded by ratepayers to develop a project owned by parties who are likely to become qualifying facilities (QF). PG&E would be required to purchase all power derived by this QF at avoided cost. Thus, for their $13.9 million contribution, ratepayers would not necessarily receive power at a discount below avoided costs.

Based on the limited amount of information in this record about the project, we are not prepared at this time to allow ratepayer funding of this project. In particular we are not convinced that the patent rights which PG&E will obtain for $13.9 million are of sufficient value to ratepayers to justify such a sizeable contribution. Accordingly, PG&E's request for funding the Carrisa Plains Project is denied.

b. Prior RD&D Expenditures

In Exhibit 16, PG&E requests the following ratemaking treatment of RD&D expenditures:[5]

1. All pre-1984 CWIP balances associated with current RDandD projects would be placed in rate base pending their cost recovery by amortization over four years.

2. All pre-1984 CWIP balances associated with completed RDandD projects would be treated as in item 1, except that the unamortized balances would not be included in rate base. (Exhibit 60, p. 5.)

[5] In D.82-12-055, we adopted the definition of RD&D used by FERC, which excludes activities "performed in conjunction with the design, construction, or operation of plant or facilities used for the commercial production, transmission or distribution of natural gas and/or electricity" (D.82-12-005, Appendix A page [illegible]). PG&E applies this definition to distinguish the RD&D portion of its CWIP balances from preconstruction studies and assessments.

The amounts associated with these balances are as follows:

Amortization of Pre-1984 RD&D
Construction Work in Progress Account Balances
(1981 Dollars in Thousands)

	Estimated 12/83 CWIP		Amount To Be Amortized In 1984*	
	Electric	Gas	Electric	Gas
Direct Costs				
Ongoing Projects	$26,659	$1,094	$6,665	$ 273
Completed Projects	1,501	6,266	375	1,567
Subtotal	28,160	7,360	7,040	1,840
AFUDC	9,776	1,850	2,444	462
Total	37,936	9,210	9,484	2,302

* Amortization over a four-year period.

The details of the above expenditures are set forth in PG&E's Exhibit 17, Chapter 6. For ongoing projects PG&E has accumulated extensive CWIP balances for research studies, including:[6]

1. Studies to evaluate the potential use of fuels other than oil and natural gas in existing power plants.

2. Studies identifying cost-effective equipment modifications, improved instrumentation and control and other methods to improve the efficiency and reliability of electric generating facilities, gas and electric transmission/distribution systems.

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6 A detailed description of these activities is presented in PG&E's March 30, 1983 response to CPUC date request #26 (reprinted in staff's RD&D exhibit, Appendix C).

3. Collecting wind resource and siting information, monitoring performance and system compatibility of customer-owned wind machines, and evaluation of reliability economics, and environmental impacts of wind technology.

4. Performing specialized laboratory and field tests to evaluate and optimize improved energy-saving gas and electric appliances.

5. Conducting research on the natural systems in PG&E's service area to improve methods of measuring, monitoring, and managing environmental impacts.

The major completed project expenditure is $6.1 million used for RD&D into coal gasification processes. The objective of the coal gasification work was to undertake cosponsored engineering, feasibility, regulatory, and other studies at several locations to develop a long-range supply of high Btu synthetic gas. Changes in economic and regulatory environments forced cancellation of these projects.

Staff argues that the costs which PG&E has capitalized for RD&D involved expenditures that never should have been accumulated in CWIP. Unlike preconstruction studies or assessments, these expenditures involved various research studies unrelated to the construction of utility facilities, and were primarily designed to develop information. The CWIP Account 107(c) only includes "expenditures for construction of utility facilities". Accordingly, these costs should have been charged to an operating expense account. Staff recommends amortization over 4 years of only the direct costs associated with ongoing and completed RD&D CWIP account balances.

We agree with staff. As discussed above it is not always the case that RD&D expenditures associated with "tangible plant" should be capitalized and recovered when the project becomes "used and useful" according to conventional accounting definitions. However, we do not believe that there is ambiguity with respect to the proper accounting treatment for the pre-1984 RD&D expenditures which PG&E, improperly, accrued in CWIP. We therefore adopt staff's recommendation to amortize over 4 years only the direct costs associated with the pre-1984 RD&D CWIP balances.

This decision does not, however, imply a precedent for the future cost recovery of abandoned or completed RD&D projects that have been capitalized consistent with our interpretation of the language in D.82-12-005, as discussed above. We see a distinct difference between the ratemaking treatment for abandoned power plant projects and RD&D projects. Since our policy on abandoned plant construction projects is set forth previously in this opinion, we will now address capitalized RD&D expenditures. As we stated, these expenditures cannot be treated in the same fashion as abandoned utility plant preconstruction costs.

Most demonstration projects that lead to tangible plant are unlike utility generating plant, where performance criteria are known factors, designed into the plant, which can be measured after the plant begins to produce energy. If research is to be treated just like any utility plant, with ratemaking treatment totally dependent upon the success of the project and determined only after the RD&D phase is over, it is very unlikely that a utility would ever undertake these types of RD&D projects. Determining that a promising technology is not commercially feasible is in itself a useful result, in that it avoids a utility investing more funds, and provides useful information about the technical or commercial viability of resource options.

We therefore believe that it is reasonable to allow accumulation and ultimate recovery of AFUDC on CWIP balances for approved RD&D projects, if the utility has diligently and reasonably completed such a project which leads to tangible plant. This policy is consistent with our discussion in Edison's last rate case. It should be emphasized again, however, that recovery of accumulated AFUDC must occur only after the project has been extensively scrutinized. In no way should allowance of AFUDC for some RD&D projects be an indication of our willingness to underwrite all such projects no matter how poorly conceived or managed. Further, as discussed in D.82-12-055, failure to request ratemaking treatment for a completed or abandoned RD&D project does not constitute good management practice (mimeo. p. 52).

5. <u>Deferred Maintenance</u>

<u>General</u>

This issue concerns PG&E's deferred maintenance request of $7,651,000 for its electric department and $3,007,000 for its Gas Department, in 1981 dollars.

The staff uniformly disallowed PG&E's proposed maintenance expenditures defined as "deferred" maintenance based upon its interpretation of the Commission's treatment of deferred maintenance expenditures in Edison's last general rate case (D.82-12-055 dated December 13, 1982, mimeo. p. 35.)

<u>PG&E's Position</u>

PG&E argues that the staff treatment of its proposed maintenance costs is wrong for several reasons:

1. The facts supporting PG&E's request clearly distinguish it from the situation in the Edison decision.
2. For several years PG&E has consistently and substantially overspent its rate case maintenance allowances.
3. PG&E has established maintenance priorities that ensure the most efficient and safe operation of its electric and gas utility systems.
4. There is a severe definitional problem concerning what is or is not "deferred" maintenance: many of the maintenance programs defined as "deferred" maintenance are in fact new or expanded maintenance activities designed to improve service reliability.
5. The disallowance of "deferred" maintenance constitutes a direct and pernicious assault on the basic ratemaking concept that utility management must be allowed to manage.
6. "Deferred" or "rescheduled" maintenance is basically a product of inadequate expense allowances; in the maintenance area in

particular, the utility and the staff have regularly estimated, and the Commission adopted, inadequate test year allowances.

7. If the Commission wants to ensure that sufficient funds are expended on maintenance activities, there are clearly better ways to meet that goal.

In analyzing the Edison decision and its relationship to the present situation, PG&E points out that: (1) the activities in question were budgeted when a tenuous financial condition existed for PG&E in 1981, the year of deferral; (2) the $74.6 million for its electric department compared to the Edison test year request of $32.6 million is a much smaller amount; (3) contrasting the 52% increase for maintenance authorized Edison, with the staff recommended 25% increase for PG&E's electric department, PG&E's maintenance budget will not be increased to a sufficiently high level to ensure the avoidance of "deferred" maintenance in some future period, if the Commission adopts the staff recommendation; (4) the great preponderance of the Edison request of $32.6 million--i.e., $30.9 million--was related to steam production expense. In contrast, PG&E's request is spread throughout production, transmission and distribution maintenance areas.

According to PG&E, the Commission in the Edison decision appeared to be most concerned about the "deterioration of the operating efficiency of [Edison's] plant which ultimately results in reduced reliability and safety" and "can lead to additional fuel costs which are borne by the utility's customers." In 1981 when PG&E deferred the maintenance activities that it seeks funding for in this proceeding, PG&E notes it spent approximately $57 million on steam production maintenance expense while only receiving approximately $32 million in rates. Then in the last recorded year--1982--PG&E was authorized $47,586,000 for steam power generation maintenance activities, and spent $64,861,000--$17,275,000 or one-third more than included in rates (Exhibit 389). Thus, PG&E argues the Commission's concerns about Edison's underspending on steam plant maintenance are simply not applicable in PG&E's case.

PG&E submits that it derived the approximately $10.5 million worth of "deferred" maintenance activities included in this rate case by looking at maintenance activities that were at one time included in its 1981 budget and for various reasons were not performed during 1981. According to PG&E some of these activities might have been included as activities used to determine the 1980 test year rate case allowances. Many were new programs, developed during 1981, and were not even planned at the time rates were adopted for 1981. Thus, "deferred" maintenance cannot be interpreted simply as activities that were previously funded in rate cases that PG&E subsequently decided not to do. Many of these activities should be treated as new programs, or programs unfunded in previous rate cases. Accordingly, PG&E categorizes the deferred maintenance expenditures as follows:

(1)	Rescheduled Maintenance (due to giving higher priority to maintenance necessary to prevent near term deterioration of efficiency and reliability)	Electric	$ 5,258,000
		Gas	$ 2,127,000
(2)	Accelerated or Expanded Reliability Improvement Programs	Electric	$ 1,282,000
		Gas	$ 752,000
(3)	Third Year of Three-year Reliability Programs	Electric	$ 659,000
		Gas	-
(4)	New Programs	Electric	$ 110,000
		Gas	$ 128,000
(5)	Maintenance Deferred from Prior Time Periods	Electric	$ 131,000
		Gas	-
		Total	$10,447,000

In view of the several categories of so-called deferred maintenance, PG&E argues that if the Commission decides to disallow "deferred" maintenance then it must recognize that many of the activities called "deferred" maintenance are for new maintenance programs and that some activities were never funded in rate cases.

Next PG&E argues that blanket disallowance of "deferred" maintenance costs constitutes very bad ratemaking policy and threatens the basic concept that managment must be allowed to manage. In effect, PG&E argues it is being told not to manage maintenance activities. According to PG&E, the essence of management is to set budgets and priorities for expenditures, and then to generally live within those plans. In contrast, according to PG&E, the staff position is that there is no management discretion concerning maintenance activities, and no ability to set priorities based on engineering judgment. Also, once a maintenance activity is identified, it must be performed or the utility will not be able to obtain the necessary dollars in some future rate case.

PG&E further contends tht the staff position is not just limited to maintenance activities that were identified and funded in a prior rate case. According to PG&E, if the utility defines any maintenance activity in its budgetary process--even if that activity was not contemplated or funded by the last general rate case decision--it must be performed in the year it is included in the budget, or there will be no cost recovery.

PG&E emphasizes that if the Commission expects the utility to manage, then it must give utility management the discretion to set priorities for maintenance activities. A blind injunction to do all identified maintenance is unworkable.

PG&E notes that the Commission expressed its policy concerns regarding "deferred" maintenance as follows:

> "For us to authorize Edison's recovery of deferred maintenance would establish an undesirable precedent, whereby the utility would effectively [be] guaranteed that it can earn (or exceed) its authorized rate of return, regardless of its operating efficiency or inefficiency, simply by curtailing current maintenance activities, in the assurance that they could be refinanced later through recovery of deferred maintenance expenses in a succeeding rate case. This would create a perverse incentive for the utility to defer needed maintenance in the future." (D.82-12-055, p. 37.)

PG&E believes the Commission's concern is that a utility will curtail its maintenance expenditures to ensure that it earns its rate of return. According to PG&E, this concern can be obviated by a simple solution: Require that a utility spend all of the maintenance dollars it received in rates. Once informed that maintenance allowances must be spent in the test period, PG&E believes there would be no incentive--"perverse" or otherwise--to underspend on maintenance.

In fact, PG&E notes that in D.93887, it was required to file a report with the Commission listing the maintenance dollars expended in 1982, and comparing those dollars with the funds provided in rates. This report (Exhibit 38) shows that PG&E exceeded its maintenance allowances in 1982.

c. Staff Position

According to staff, the issue of deferred maintenance involves two policies:

The first is the policy which the Commission announced in the Edison D.82-12-055. Staff contends that the "deferred" maintenance request of PG&E in this proceeding corresponds exactly to the type of deferred maintenance request made by Edison and which was disallowed by the Commission.

The other policy which according to staff clashes with the aforementioned Commission policy, is the policy of PG&E, as represented by its Chairman of the Board and Chief Executive Officer, to seek to limit expenses in any given year to the level authorized in rates. As analyzed by staff, this policy would seek to relieve PG&E of the responsibility and the risk for incurring any expense in excess of that anticipated when rates were set.

Staff argues that PG&E's request closely matches the circumstances under which Edison requested deferred maintenance during its 1983 test year rate case and about which the Commission stated:

> "Rather than spend dollars for maintenance beyond those authorized in rates as Edison has done in prior years, Edison decided to defer it in order to increase shareholder dividends and improve the company's earnings." (D.82-12-055, mimeo., p. 35.)

Staff contends that the deferred maintenance which PG&E requests was deferred for precisely the same reason. Refering to the numerous times PG&E's witnesses stated that items were deferred for "engineering judgment reasons and that such deferral would not cause damage to the system," staff argues that such deferral was to live within the financial constraints imposed by PG&E's management, in an attempt to earn the utility's authorized rate of return.

Staff contends that the process of deferring maintenance involves two types of judgment, an engineering judgment decision to determine whether the maintenance can be deferred with minimal impact upon efficiency and reliability, and the actual decision to make the deferral which has to be a business judgment on the ground that a certain amount of money was to be saved. According to staff the financial constraints and that business judgment represent the day-to-day impact of policy which PG&E has enacted.

Staff further notes that the Commission summarized the concern raised by the practice of deferred maintenance as follows:

> "Staff, however, is concerned that deferral of maintenance does not conform to good operating practices. By deferring maintenance the utility risks deterioration of the operating efficiency of its plant which ultimately results in reduced reliability and safety. It can also lead to additional fuel costs which are borne by the utility's customers." (D.82-12-055, mimeo. p. 36.)

According to staff, the consensus of both the utility and the staff witnesses is that portions of PG&E's electric system are experiencing deterioration at the present time. Staff notes that PG&E's witness on the electric distribution system conceded that there has been a measurable decline in distribution service reliability as well. Staff argues that in the long run, continued deferrals of maintenance of this type will have a further deteriorating effect on PG&E's system.

Finally staff argues that its estimates are not meant to be budget estimates to be utilized as such by the utility. The staff estimates are for ratemaking purposes and are meant to approximate normal or average year conditions rather than to decide that a particular project should be done or certain amount of dollars should be spent in a certain account in any given year. The utility's stated policy of "living within" the authorized levels of expense from the general rate case is an attempt to distort this process by treating the staff ratemaking estimates as if they were actual budgets.

d. Discussion

The basis of staff's argument is that the necessity to spend more than was authorized for any particular type of expense is a normal consequence of test year ratemaking. The theory is that the utility will spend more some years and less in other years. In the long run, the over- and under-expenditure is supposed to even-out. We agree that for the last several years, this theory in PG&E's case has not been proven in practice. The reason is that in the last few rate cases, PG&E, the staff, and the Commission have consistently underestimated maintenance expenses.

As we see it, the problem lies in the estimating techniques. Therefore, the remedy is more accurate test year expense estimates rather than an allowance for deferred maintenance.

Our concern is that if the Commission strays from the current view of the traditional ratemaking responsibilities of the utility and the staff, it risks distorting the ratemaking process significantly. Permitting deferred maintenance to be recovered simply because the utility says it did not have sufficient dollars to perform a maintenance item in a prior year and it wishes to do so in the future would be to give what is, in essence, balancing account treatment to maintenance expense, under which the utility can recover whatever it claims is reasonably necessary at some point in time.

Returning to the specific items labelled as "deferred maintenance", we should point out that PG&E's financial condition at this time is certainly different from what it was in 1981 when we authorized over $900,000 of deferred maintenance in PG&E's 1982 test year. We see no justification to deviate from our policy which is set forth in the Edison decision. Accordingly, we will disallow PG&E's entire request for deferred maintenance. We see no reason to distinguish between different categories of deferred maintenance.

We note it was PG&E that labelled the items in question "deferred maintenance". In view of our blanket denial of PG&E's requet for deferred maintenance expense, we fully expect PG&E will remove the words "deferred maintenance" from its rate case lexicon for the future.

On the other hand, we realize that a blind injunction to do all identified maintenance is unworkable. In the first place, the spectrum of potential maintenance activities is basically endless. Individuals disagree on the nature and extent of maintenance that must be done. An engineer operating a given piece of machinery, due to his or her limited perspective, may identify maintenance opportunities that management either believes are unnecessary or may be deferred. Management must have the discretion to set priorities for maintenance activities.

The reasonable way to evaluate a utility's maintenance activities is to ask whether the utility acted reasonably in maintaining its system. Did management identify needed maintenance? Did it set the proper priorities for performing maintenance? Did management set the proper priorities between maintenance activities and other utility activities?

In order to accomplish these objectives, we realize that a utility must continuously update its in-house budgets for planning purposes. The mere fact that a maintenance activity is added to such a budget and later dropped will not automatically qualify it for later disallowance in a rate case proceeding. Certainly, this is not the result we intend by our disallowance for "deferred maintenance" in this proceeding.

Looking back on this phase of the proceeding, it is our conclusion that the utility and staff should get back to their traditional roles in the ratemaking process. The staff should try to make as accurate as possible an estimate of expected average year conditions for the test year. It should not attempt to define precisely what items of maintenance should be performed in a given year at a given time. As the utility itself pointed out through cross-examination, if the staff were to attempt to itemize maintenance in such a fashion, it would create another perverse incentive where the utility's managers would be impelled to perform the maintenance identified by the staff in order to avoid any sort of penalty, and this could be at the expense of other more important maintenance which has come to their attention since the rate case.

The utility, on the other hand, should return to the practice of attempting to run as efficient an operation as possible in all aspects. This includes cutting costs to try to avoid expenses which are not necessary, but also implies spending that which is reasonably necessary to maintain its operations and its plant in the condition to provide efficient and reliable service. If to achieve that condition requires more or less than the Commission has authorized, the utility's financial condition will be affected accordingly. The key is to make accurate estimates of maintenance expense to avoid large over- or underexpenditures.

6. Attrition Rate Adjustment (ARA)

PG&E and the staff both agree that the basic ARA adopted in D.93887 (PG&E's 1982 General Rate Case), as modified by D.82-12-055 (Edison's 1983 General Rate Case), and D.82-12-112 (PG&E's 1983 ARA case), should be employed in determining PG&E's 1985 Attrition Year allowance. PG&E and staff also agree that four new items, representing additions or modifications to the ARA, should be added to the ARA.

First, the staff and PG&E agree that the new labor and nonlabor indexing formula or equation introduced in D.82-12-112, should be used in the ARA calculation for 1985. This formula can be found in staff Exhibit 57, at pages 3-BMD to 4-BMD, and in PG&E's Exhibit 6-A, at page 3. This formula provides that a corrected estimate of inflation in Test Year 1984 will be used in determining the 1984 base labor and nonlabor costs which are to be escalated by the fall 1984 DRI forecast to derive the 1985 expense allowances.

Also, the staff and PG&E agree that the labor and nonlabor escalation rate methodologies adopted by the Commission should be used within the indexing formula. Specifically, the labor escalation rate calculation should be based on the labor contract negotiated in 1983 and in effect at the time of the Commission's decision.

Second, staff and PG&E agree that there should be a fixed attrition line item reflecting the increase in CPUC-Jurisdictional Electric Department costs. The reason is that more of total costs will be allocated to the CPUC Jurisdictional portion of PG&E's utility operations because of a decrease in the sales to Federal Energy Regulatory Commission (FERC) jurisdictional customers.

Third, the staff and PG&E agree that the ARA should include a line item for attrition year Feasibility Studies income tax effects if the Commission decides to flow through the state income tax benefits associated with Feasibility Study tax write-offs in 1984. PG&E does not believe that such flow-through treatment should be followed. However, if it is followed, then the flow-through of state tax benefits reduces the revenue requirement in 1984, the year of the flow-through, but increases it in 1985. The amount in question is $18,200,000.

Fourth, PG&E and staff agree that the cost of postage increase for 1985 should be reflected in the ARA, if such an increase is approved by the Postal Commission prior to filing the ARA.

We will adopt the above four recommendations.

PG&E and staff disagree over several of the individual estimates. First, the Labor and Non-Labor Bases to be used for indexing represent the staff's and PG&E's divergent estimates of Test Year 1984 costs. We will reflect the adopted levels of expenditure in the 1985 ARA.

Second, staff includes in its ARA showing the recommendation of the staff load management witness for a negative revenue requirement adjustment for load management in 1985. Since we are not adopting this adjustment, the staff's negative $9,486,000 (Electric) and $1,508,000 (Gas) adjustment will be removed from the attrition calculation. The adopted 1984 load management expenses are included. Also, we will reflect a positive attrition adjustment equal to the credit against 1984 revenue requirements that is made to reflect the 1982-1983 conservation and load management funds which were not expended, modified to reflect results of the true-up calculations described in Section V.A.

Third, PG&E determined its Attrition Year 1985 rate base in the same fashion as it calculated its 1984 rate base — through study of anticipated rate base additions. The staff, in contrast, used a forecasting methodology based on a 5-year (1978-1982) average plant additions per customer figure and then combined this calculation with a working capital allowance calculation. Staff separately included major 1985 plant additions which PG&E and staff categorize as items over $10 million. We conclude that the staff approach, which was used in PG&E's last general rate case, is reasonable and we will continue to use it for 1985.

Fourth, PG&E and staff disagree over the appropriate financial attrition adjustment. We will reflect the adopted costs of long-term and preferred stock.

Fifth, and most importantly, the staff seeks to disallow $59,036,000 and $4,167,000 in expenses related to activity growth in 1985 for the Electric and Gas departments, respectively. This activity growth includes $11,348,000 for conservation and $6,361,000 for load management programs in the Electric Department. The staff has allowed only $2,421,000 in activity growth for conservation and deleted the Load Management program, subject to review.

The staff recommended disallowance is based on the assumption that savings from "productivity improvements" in 1985 will totally offset cost increases resulting from activity growth in 1985. PG&E disagrees.

This important issue is considered in the productivity discussion in the policy section of this opinion and we will not repeat the arguments. However, the adopted attrition allowance will reflect the staff approach, except that no attrition adjustment will be made in the conservation and load management areas other than that reflecting labor and non-labor escalation.

Finally, we should point out that the attrition allowance is not intended to cover every conceivable area where the utility can foresee possibility of an increase from the test year. It is only intended as a reasonable allowance to get by in the second year of rate life. If productivity increases do not offset increases in expenditures, we suggest that the utility pull-in its corporate belt a notch tighter.

We set forth the adopted attrition allowance for 1985 in the Results of Operations section of this opinion.

Pacific Gas and Electric Company
Electric Department
ATTRITION YEAR 1985
(000's Omitted)

Description	PGandE	CPUC Staff	Adopted
Indexed Attrition (Base for Indexing)			
Labor	$622,507	$551,778	$570,276
Non-Labor	424,911	327,828	327,272
Fixed Attrition			
Activity Growth			
Labor	12,974	0	0
Non-Labor	30,819	0	0
Conservation	11,348	2,421	0
Load Management Adjustment	6,316	(9,486)	0
Postage	0	0	1/
PCB Transformer Replacement Program	1,933	1,766	1,743
Depreciation Expense	58,022	45,777	46,238
Ad Valorem Taxes	4,004	1,747	1,765
Income Tax Expense	(18,489)	(12,417)	(12,520)
Research and Development (Cheng Cycle)	—	—	2,250
Rate Base, Including Working Capital	65,763	43,099	43,965 2/ 3/
Jurisdictional Allocation	10,110	2,215	2,215
Financial Attrition	10,047	5,026	5,658
Total (Fixed Items)	$192,847	$80,148	$91,314
Conservation/Load Management Adj.	--	--	-4/

1/ Postage increase to be included only if known.

2/ Working capital to be determined consistent with factors in Exhibit 212, Attachment A.

3/ Includes estimated 1985 load management capital addition of $6,945,000

4/ Increase attrition allowance by $22,996,000 less the correction amount as discussed in the Conservation, Load Management Past Underexpenditure section.

Pacific Gas and Electric Company
Gas Department
ATTRITION YEAR 1985
(000's Omitted)

Description	PGandE	CPUC Staff	Adopted
Indexed Attrition (Base for Indexing)			
Labor	$284,007	$257,697	$263,381
Non-Labor	155,949	132,044	134,407
Fixed Attrition			
Activity Growth			
Labor	2,095	0	0
Non-Labor	2,072	0	0
Load Management Adjustment	0	(1,508)	0
Postage	0	0	0 1/
Depreciation Expense	19,783	16,376	16,474
Ad Valorem Taxes	1,056	286	288
Income Tax Expense	(3,586)	806	777
Rate Base, Including Working Capital	29,735	10,218	10,559 2/
Financial Attrition	3,367	1,613	1,801
Total (Fixed Items)	$54,522	$27,791	$29,899

1/ Postage increase to be included only if known.

2/ Working capital to be determined consistent with factors in Exhibit 212, Attachment A.

7. <u>Humboldt Bay Unit No. 3</u>

Prior to the commencement of evidentiary hearings in this case, the staff filed a motion to require PG&E to cease the accrual of AFUDC related to the Humboldt Bay Nuclear Power Plant (Humboldt). This motion was filed on January 28, 1983 and the first hearings on this particular matter occurred March 18, 1983. In addition to seeking a change in the way in which the utility recorded the expenses of its out of service nuclear plant at Humboldt, the motion also asked for the utility to provide an additional study of the feasibility of re-commissioning the plant.

On May 18, 1983 in D.83-05-151 the Commission granted the staff's motion in an interim opinion which among other things provided that AFUDC should no longer be accrued by PG&E on the Humboldt plant and in addition provided, as the staff has recommended, that the O&M expenses related to Humboldt should be reflected in the 1984 and subsequent test year revenue requirements. Previous to this decision, while the plant had been out of service, these expenses had been capitalized.

Subsequent to D.83-05-051, PG&E announced on June 27, 1983 that it had decided to decommission Humboldt. The economic feasibility study provided by the utility as ordered by the Commission demonstrated that it would not be cost effective to retrofit the plant under any probable scenario involving Nuclear Regulatory Commission (NRC) requirements for retrofitting older plants. Subsequent to this announcement by PG&E the utility filed Exhibit 207, a current expense recovery proposal for Humboldt, Unit No. 3. In this exhibit, the utility estimated that O&M costs for each of 1984 and 1985 would be $1,938,000. In addition, the utility requested in each of those years $1,824,000 for fees to handle spent fuel related to the plant. This fee would be paid to the federal government for the handling of spent fuel.

Exhibit 207 also included a summary of projected costs required for decommissioning of the plant and for recovery of capital costs associated with the entire life of Humboldt. The utility indicated and the Commission staff agrees that the expenses associated with placing the plant in a safe storage mode, estimated by PG&E to be $16 million, and the decommissioning costs of the plant, estimated by PG&E to be $49 million, should be recovered after a decommissioning mechanism has been ~~established in OII 86, the~~ generic proceeding established by the Commission to establish the procedures for decommissioning nuclear plants in California. However, the $83 million of capital cost recovery identified in PG&E's Exhibit 207 must be sought through a separate proceeding to recover such costs since these costs have not been examined by the staff in this proceeding.

Subsequently, PG&E filed an additional exhibit regarding Humboldt's O&M expenses, Exhibit 235, which detailed the insurance expenses the utility estimated it would incur with respect to the Humboldt plant in the test year and in 1985. The estimate is $429,000 in 1984 and $502,000 in 1985.

The staff conducted a review of the projected O&M expenses for the Humboldt plant including an examination of the spent fuel fees that PG&E could be expected to incur during the test year and in 1985. Staff received a letter dated June 30, 1983 from PG&E, stating that the fees for handling of spent nuclear fuel would in fact be paid to the Department of Energy (DOE) on or before June 30, 1985. The utility's estimate for these spent fuel fees includes a discount to consider the cost of money between the inclusion of these fees in rates and the date in mid-1985 when the fees will be paid. On the basis of this information, staff witness Kevin Coughlan testified that such spent fuel fees were in fact reasonable and should be included in rates. Additional investigation by the staff indicates that the estimated O&M expenses requested by PG&E are reasonable and should be added to estimates of expenses for the test year.

We concur with and will adopt staff's recommendation.

8. Street Lighting Plant Sales

In discussing PG&E's several recent sales of streetlighting systems to municipalities and counties, PG&E's witness Thomas Long stated that the utility had not filed applications with this Commission, pursuant to Section 851 of the Public Utilities Code because it was of the opinion that this code section did not apply to such sales.

This matter is discussed in detail commencing at page 105 of the staff opening brief and page 101 of PG&E's reply brief. We see no need to reiterate the arguments. However, PG&E submits that:

> "PGandE's difference of opinion regarding the necessity to file Section 851 applications for streetlight sale transactions implies no disregard of Commission authority. PGandE's good faith is evidenced by the fact that as soon as the issue was raised in this proceeding, it filed Application No. 83-06-11 to seek to resolve whether Section 851 applications are required for sales of streetlight systems.
>
> "Now that the Commission has resolved this legal uncertainty (D. 83-06-096) PGandE will henceforth file Section 851 applications before voluntarily conveying streetlight systems." (Page 106, Reply brief.)

PG&E's future compliance with Section 851 is now settled and we need not pursue the matter any further.

We should mention that D.83-06-096, in the application by PG&E to convey streetlighting facilities in the City of Arcata, also briefly touched upon the issue of the disposition of the profits from any sale of streetlighting plant. The Commission reserved deciding that issue in the Arcata proceeding and specified that the issue would be briefed in PG&E's A.83-04-037 which is an application regarding the sale of certain facilities of the City of Redding.

9. Long-Term Planning

In D.82-03-047 dated March 2, 1982, the Commission instructed PG&E in the following language: "In its next general rate case application, PG&E shall submit to the Commission its then current resource and supply plans, including comparison of the energy and financial impacts of alternative energy supply and conservation projects." (Ordering Paragraph 19.) In compliance with this order, PG&E and the Commission staff both prepared anaylses of PG&E's long-term resource plan.

The PG&E exhibit (Exhibit 3) was prepared by the company's vice president for Corporate Planning, Mason Willrich. The Commission staff's long-range planning exhibit (Exhibit 64) was prepared by William Ahern, Director of the Utilities Division of the Commission. While the two reports approach long-term planning from different perspectives and use different methodologies, they essentially arrive at similar conclusions.

Specifically, PG&E agreed with the staff that major uncertainties, particularly with respect to oil prices, still plague long-term planning efforts and that the passage of two years time between now and the next general rate case may be a useful period in which to avoid major changes in direction of resource planning and to simply observe what trends in oil prices and the economy are apparent at that time.

PG&E's exhibit contains no recommendation that major capital-intensive generation projects should be initiated immediately because the utility's generation resources should be adequate to meet demand in the immediate future. Faced with this window of time, both the utility and the staff concur that more effective planning might be done after world economic conditions have stabilized. This "wait and see" posture is reflected in the recommendations of both witnesses who agreed that there was no need to either strongly accelerate conservation and load management programs at this time, or to enter into new capital-intensive generation projects, although the utility remains interested in completing those major capital projects which are under construction.

Two criticisms of the long-term planning exhibits themselves surfaced during the hearings.

The staff criticized PG&E for making one single set of assumptions about key economic variables that affect planning decisions. PG&E does present three different cases of long-term planning options: a base case, which represents the most likely or preferred strategy; a high conventional case, which emphasizes the construction of conventional generation facilities such as oil, gas, coal, or nuclear plants; and a high alternatives case which emphasizes conservation and the utilization of alternative energy sources. However, the desirability of any of these three cases and the accompanying risks of each are strongly impacted by the assumptions made regarding oil prices, economic conditions, interest rates, and the like.

The staff's criticism is based upon the fact that a decision-maker would have a great deal more useful information with which to consider the three cases if PG&E had presented a range of possibilities for the various economic assumptions rather than presenting only one fixed set of assumptions. PG&E's witness concurred that the assumptions used in the long-term planning exhibit are subject to major uncertainties. He further agreed that differing assumptions would change the desirability of the various cases, although PG&E did not provide any sensitivity analysis in this regard.

Staff notes that according to the three cases prepared by PG&E, under the assumptions contained in the long-term planning report, the rate impact of each of the alternatives is sufficiently identical to all of the others so that any differences are smaller than the statistical margin of error of the analysis.

We agree with staff that a sensitivity analysis will be helpful. Accordingly, we will expect PG&E to include such an analysis in its next resource planning exhibit. PG&E will provide a long-term planning exhibit in its next general rate case proceeding.

Also, in PG&E's next long-term planning exhibit, we expect PG&E to explicitly demonstrate how the estimated costs of the resources available to the utility and the utility's preferred resource plan combine to formulate a least-cost strategy for additional generation in the future.

The second criticism leveled at the long-term planning exhibits is contained in the testimony of the California Energy Commission (CEC) witness. It concerns the appropriate planning assumption to adopt concerning the expected long-term price of oil. The CEC projects that the current favorable supply in the oil market is temporary, that market real price increases on the order of 3% annually are the basis for prudent planning, and that use of oil has heavy external costs in addition to its market price.

Testimony on behalf of CEC was presented by its witness, Sanford Miller. Essentially the CEC position is that the Commission cannot afford to take "a wait and see" posture regarding the development of conservation and alternative resources because:

a. In the long-term planning horizon, the world price of oil is far more likely to increase than to decrease.

b. The public interest in reducing PG&E's reliance upon oil and gas goes beyond the dollar costs considered in this rate case.

c. There is a compelling need to continue the growth in PG&E's programs for conservation and alternative renewable resources.

The staff disagrees with the CEC contention that imported oil carries with it significant external costs which should be added to the cost of the oil when making long-term planning decisions.

Staff believes any such premium would in essence be double counting of the economic impact of imported oil. Staff notes that the CEC witness indicated that this premium should be added to the marginal price of the oil. Furthermore, staff notes that the marginal cost of producing oil is in many instances well below the marginal price of oil. It is the position of the staff that the high price which OPEC and other foreign producers charge for oil is a direct result of their taking advantage of Western dependence on oil. Furthermore, staff notes that a recent Energy Commission committee report on fuel price projections states that it is uncertain whether or not the current Energy Commission oil price forecasts include any such premium.

In the view of the staff, accurate forecasting of oil prices using conventional methods is far preferable to trying to calculate some additional premium to be added to those prices based upon speculation of external costs which are not themselves accounted for by market processes.

We recognize the concerns of CEC. We agree that oil prices are a significant uncertainty and higher prices are plausible. However, we note that, at this time, there are sufficient resources on the PG&E system to allow a two-year window before major planning decisions must be made.

Since the choice of a resource strategy is currently dominated by uncertainty, we believe the prudent course is to maintain the current levels that have been achieved in conservation and load management. We have to bear in mind that this Commission has the responsibility to develop short and long-term plans to meet customers needs at reasonable cost. Accordingly, we will adopt our staff's strategy recommendation.

The planning strategy for the 1984-1985 test period was set forth by staff witness Ahern as follows:

> "Because of these uncertainties, it seems prudent to follow neither path [i.e. accelerated conservation and load management activities versus decelerated activities and greater reliance on oil and gas fired plants] and to adopt a hedging resource strategy for PG&E that keeps resource options open, that makes no major commitments over the next two years, and that neither increases nor decreases currently funded and designed conservation and renewable resource programs." (Exhibit 64, p. 1-1.)

The CEC's witness mistakenly believes that the "hedging" strategy involves a retreat from conservation, load management and alternative energy resources. It does not. Both PG&E and the Commission staff recognize that PG&E can continue to promote conservation, load management and alternative resources and rely on these resources as a critical component of the utility's resource plan without either unjustified expansion of these activities or paying excessive prices for power at great cost to ratepayers. If increasing these activities cannot be justified using the generally-accepted measures of cost-effectiveness, then caution should prevail.

10. Female-Minority Business Enterprise Programs

On January 28, 1983, PG&E filed a report detailing its activity to increase the participation of female and minority business enterprises in the procurement of PG&E's goods and services. This report was filed in compliance with Commission D.82-12-101. That report is entered into evidence as Exhibit 113 in this proceeding, and subsequent to its filing, the staff and the utility provided witnesses to discuss the implementation of the programs described in that report.

The ultimate conclusion of the staff's investigation is that the program to enhance the participation of female-minority business enterprise vendors established by PG&E is essentially in compliance with the Commission's decision and with the intent of that decision. However, a major concern of the Commission as voiced in D.82-12-10, and which still is a concern, is the ability of the Commission to monitor the impact which such a program will have on the actual patterns of expenditures by PG&E for procuring supplies from female and minority business enterprises.

To further the monitoring of this program, the staff recommends a particular reporting form be developed which will catalog not only utility expenditures to purchase goods or services from female or minority business enterprises, but also catalog complaints filed by those same business enterprises and an explanation of the resolution of those complaints. As of the date the staff witness testified in this proceeding there was not complete agreement between the staff and PG&E as to the exact form of reporting document which should be used, but additional conferences were held between the staff and the utility and agreement on a form to be used was reached after the case was submitted July 15, 1983. The resulting compromise reporting form was provided to all parties through letter of counsel.

To the extent that the staff has reviewed PG&E's report on its program to enhance female-minority business enterprise participation in the procurement of goods and services, the staff has found PG&E in compliance with the Commission's orders. Also, to the extent that a satisfactory reporting form to monitor that program has been developed and will be implemented, the staff believes that it has fulfilled the mandate given it by the Commission in D.82-12-101, and no further action need be taken in this particular proceeding. The staff will, of course, continue to monitor the results of the program as reported on the forms developed in this proceeding and will report on those developments to the Commission in appropriate proceedings in the future.

Public Advocates, Inc., on behalf of the U. S. Black Chamber of Commerce and other intervenors, filed its opening brief on August 31, 1983, after opening briefs were due. In its brief, Public Advocates argued that the proposed rate increase should be denied or delayed due to the alleged failure of PG&E to comply with D.82-12-101. Public Advocates claims that PG&E is not in compliance with the decision in that its statistical filing does not report on each ethnic group separately and does not report on each type of contract separately. As further evidence of noncompliance with the decision Public Advocates notes that the female-minority business enterprise share of contract awards is less than the percentage of females and minorities in the general population. (Public Advocates Brief, pp. 2-3.)

PG&E points out that the plain language of D.82-12-101 does not require separate statistics for each ethnic group or for each type of contract. Rather, it requires "statistics for the last five years' recorded data showing total amount contracted for goods and services. ...and amount of contracted for goods and services from minority- and women-owned businesses." (Interim Order, D.82-12-101, p. 33.)

Further, PG&E argues that its filing met both the letter and intent of D.82-12-101; and if Public Advocates had wanted additional data, it should have said so before now. Instead Public Advocates waited until the record was closed before seeking additional data.

PG&E also submits that nothing in the decision, and nothing in civil rights law, requires or contemplates parity between contract awards and general population as Public Advocates contends. PG&E cites White v. Washington Public Power Supply System, 692 F.2d. 1286, 1289 (10th Cir. 1982), where the Court held that an employees' statistical evidence comparing an employer's female and minority-group employees with the state's general population of women and minority-group persons, instead of with the available population of qualified women and minority-group persons, was entitled to "little or no weight."

We reject the proposals contained in the brief filed by Public Advocates, Inc. We are satisfied that Public Advocates Inc. had ample opportunity to make its case in this proceeding which lasted several months. The Commission staff went to unusual lengths to have Public Advocates Inc. participate in this proceeding but to no avail.

We are satisfied that the mandates of D.82-12-101 are being carried out at this time. However, we remind PG&E that it is under a continuing obligation to increase minority and female business participation in company procurement. We envision steady progress in this area. Therefore, in addition to the requirements of ordering paragraph 1 of D.82-12-101, we will require PG&E,

in its next general rate case, to submit data in the format agreed to by staff and the company. Should Public Advocates or any other interested party feel that PG&E's efforts are inadequate, it should actively participate in the general rate case proceeding.

11. Franchise Fees

a. Surcharge

Staff proposes that an increase in franchise fees recently adopted by the City of San Jose (San Jose) for gas and electric service provided by PG&E within its city limits be collected as a surcharge only from the City of San Jose residents to the extent that it exceeds the current average franchise fees paid by all ratepayers in the PG&E service territory.

We should explain that a franchise fees is not a tax upon property or a license charge for the privilege of operating a business; it is compensation for the privilege of using streets and other public property within the territory covered by the franchise.

All the cities and counties in PG&E's service area were notified of this issue and hearing date. Letters were received from eight cities urging the Commission not to pass on to all ratepayers the higher franchise fee of San Jose.

The Vice Mayor of Fremont, Bob Reeder, testified that in his opinion the present situation had inequities since there were a greater number of cities receiving only half a percent franchise fee. He acknowledged that Fremont was benefiting from this inequity because Fremont had a 1 % fee. He urged that a surcharge be added to all PG&E bills to rectify the unfairness so that customers in each city pay their own city's excess franchise fees.

San Jose presented a complete showing on the franchise fee issue through its witness Ralph E. Andersen. San Jose's brief and Exhibits 123 through 128, 192 and 193 provide much information which we will not repeat for the sake of brevity.

San Jose alleges that the imposition of a surcharge in the manner recommended by staff would be "discriminatory, unreasonable and inconsistent with present ratemaking policy."

Therefore, the issue is whether the staff proposal is discriminatory or in violation of any statutory or constitutional standard. Neither the staff nor any other party is contesting the right of San Jose to obtain an increased franchise fee through the terms of its franchise agreement with the utility and through the arbitration proceedings which were recently concluded.

Obviously, certain rules and regulations will cause certain parties to be treated differently than others. There has to be a reasonable or factual basis for such rules and regulations. However, discrimination resulting from a classification based upon reasonable and substantial differences will be upheld, so long as it is not arbitrary or capricious.

San Jose argues that there presently exists a range of franchise fees paid by PG&E to municipalities (both general law and charter) for the privilege of using the public rights-of-way. According to San Jose, the staff proposal does not consider the wide range of other expenses and fees paid by PG&E to municipalities, nor is there any proposal to so consider such costs and expenses on a community-by-community basis. Although San Diego has been mentioned as a precedent for this proposal, San Jose submits there are distinct factual differences between the San Diego precedent and the staff proposal with regard a surcharge in San Jose. In short, San Jose contends it is being singled out for arbitrary and discriminatory treatment.

San Jose notes that in 1980, prior to the arbitration giving rise to this surcharge proposal, there was a range of franchise fees from 1/2% to 1% on electricity and from 1% to 2% on gas. Despite these variations in rates of franchises, no surcharges are imposed in any other cities receiving greater than 1/2% of gross receipts for electricity franchises, or more than 1% of gross receipts for gas franchises. Indeed, cities receiving less than 1%

in electricity franchise fees are not credited for having such lower fees; these costs are simply averaged throughout the system.

San Jose points out that the variation in rates of franchise fees paid to municipalities within the PG&E system is further compounded by the fact that in 1978, a decision was rendered in the case of County of Santa Cruz v. Pacific Gas and Electric Company (Santa Cruz Superior Ct. No. 49748), which altered the method of computing gas franchise payments under the Broughton Act. Since 1979, many cities have received higher gas franchise payments pursuant to a Broughton Act calculation than such entities would have received under a simple percentage of gross receipts calculation, as is demonstrated by City's Exhibit 126. These higher payments vary from year to year, and in actuality result in an effective gas franchise rate which is greater than 1% for each of these cities.

San Jose argues that these variations in effective rates of franchise payments on a percentage of gross receipts basis demonstrate two glaring inequities with the proposed surcharge. First, several cities have received an effective franchise payment greater than 1% of gross receipts pursuant to a Broughton Act calculation for several years, and yet no surcharge has previously been proposed. Secondly, the staff proposal to simply surcharge 1% above the percentage of 1% which San Jose received prior to the arbitration, while other ratepayers in other cities which receive an effective franchise rate greater than 1% are not surcharged at all, is discriminatory. It requires San Jose ratepayers to assume payment of a portion of the Broughton Act franchise fees which has been averaged throughout the PG&E system and will continue to be averaged throughout the system for every city and/or county except San Jose.

In the view of the staff, the San Jose franchise fee increase, from 1% to 2%, is a significant increase and an expense which does not provide benefit to ratepayers throughout PG&E's

service territory and is also a charge which is easily identified and surcharged much as the San Diego franchise fee surcharge. Accordingly, staff argues it is fair and reasonable to break that item out into a separate surcharge to the extent PG&E's new franchise fee will be in excess of the average franchise fee collected in the PG&E service territory.

Staff further argues that San Jose has not sufficiently distinguished itself from the example of the San Diego franchise fee surcharge. The slightly differing size of the franchise fee increase from 1% to 2% in San Jose versus from 1% to 3% in San Diego and the differing size in proportion to number of customers between San Jose and San Diego to the entire utility service territory, that is, 6% to slightly over 50%, respectively, are not sufficient to distinguish the San Jose situation from that of San Diego. Staff further notes that the San Jose franchise fee increase is essentially a 100% increase in the previously authorized franchise fee.

Staff takes exception to San Jose's continual reference to the fact that two other cities within California have a 2% franchise fee as San Jose now does after arbitration. Exhibit 124 submitted by San Jose shows that only the towns of Taft and Maricopa have such a 2% franchise fee. In the opinion of staff, it would not be reasonable or efficient to impose a special billing procedure upon the utility to account for the very slight difference in franchise fee collection related to those two small cities. However, staff points out that San Jose provides 12% of the total franchise fee expense that PG&E incurs in its entire service territory. Therefore, the 100% change in San Jose's authorized franchise fee is, in the view of the staff, a sufficiently large increase to warrant action on the part of the Commission.

Staff also address San Jose's argument concerning the cities which may collect a portion of their franchise fees based on the Broughton Act calculation. In the opinion of the staff, it would be impractical and uneconomical to impose a surcharge which is constantly shifting and varying as would be the case with Broughton Act cities. Staff further notes that in San Jose's case, San Jose will use exactly 2% as the calculation for its franchise fee in most instances because it will exceed the Broughton Act calculation for the San Jose area.

The City of San Francisco (San Francisco) was actively involved in this phase of the proceeding. San Francisco argues that the staff proposal to surcharge San Jose's franchise fee is discriminatory. According to San Francisco, there is a basic inequity in averaging. Therefore, San Francisco urges the Commission to end all averaging and to surcharge each city's franchise payment to the respective customers in each city.

San Francisco notes that prior to the 2% rate adopted for San Jose, the franchise rates ranged from a low of 1/2% in San Francisco to 2% in the Cities of Taft and Maricopa with varying rates in other cities. In setting rates the Commission simply averaged all franchise payments. According to San Francisco, this created a system of unreasonable subsidies.

San Francisco further argues that prior to the San Jose change in franchise rate, the ratepayers of San Francisco were subsidizing the ratepayers in virtually every other PG&E area. The situation was even further exacerbated in 1978 when PG&E changed its method of calculation of its gas franchises under the Broughton Act. According to San Francisco, this change impacted virtually every community but San Francisco, and franchise fees were substantially increased. Other cities benefited and San Francisco paid. San Francisco notes that the staff saw no great equitable question when this occurred.

We should observe that unfortunately for San Francisco, it is locked into a 1/2% franchise fee rate. Therefore, San Francisco will be unable to follow San Jose's example. However, San Francisco should derive comfort from the fact that while it does not collect the largest franchise fee from PG&E, it has done remarkably well in other tax-related areas where costs are averaged among all ratepayers. For example, San Francisco has the highest business license tax of all the cities in PG&E's service area - $2.6 million in 1981 and considerably more for the test year. By way of comparison, it is interesting to note that in 1981 the next highest was Berkeley, $41,880 and finally Redwood City, $25. (Exhibit 127.)

We are well aware that there are fundamental differences between franchise fees and business license taxes. The only reason we raise the issue of business license taxes is because these, along with many other items, are averaged for ratemaking.

Likewise, PG&E's property taxes are also averaged. San Luis Obispo and Contra Costa each collected $11.6 million from PG&E in the 1981/82 tax year (Exhibit 128). A customer in Santa Maria might feel it is discriminatory to be charged for property taxes for the Contra Costa power plant when that customer also pays for property taxes for the San Luis Obispo power plant which arguably serves that customer.

Another concern we have is the rapidly increasing Utility User Tax levied by the cities following Proposition 13. This cost is not averaged for ratemaking but is shown as a surcharge on the customer's bill and is collected by PG&E for the cities. We have received an increasing number of complaints on this tax from customers. This is a matter which should be considered if we decide to add a separate surcharge to the customer bill to recover the franchise fee, business license tax, or any other such tax which varies from city to city.

In passing, we note that San Francisco does not levy the Utility User Tax on residential customers but does levy it on all business and commercial customers.

In conclusion, at this time we see no reason to adopt staff's or San Francisco's recommendation on the franchise fee issue. For purposes of this proceeding we will continue to average franchise fees as we have done in this past. There is a reasonable basis to continue this ratemaking treatment.

On the other hand, we are concerned that other cities will follow in San Jose's footsteps. We are well aware that following the passage of Proposition 13, the cities now seek alternative means to increase revenues. If the present situation worsens, we will be forced to adopt San Francisco's proposal of separate franchise fee surcharges for customers in each city.

Therefore, we expect PG&E to review the practical and administrative problems of implementing such a proposal. Also, we will require PG&E to update the information contained in Exhibits 123 through 128, 192 and 193. This information should be made available in PG&E's next general rate case proceeding, where we will review the need for separate surcharges for each city. PG&E should provide an affirmative showing on the implementation of this proposal.

b. Ratemaking Treatment

Staff and PG&E disagree regarding the recovery of franchise fees in two areas, the increased fee granted to San Jose, and the recalculation of the franchise fee paid to the County of Sacramento. We will address each issue individually.

(1) San Jose

On January 25, 1983, an arbitration board decision increased PG&E's franchise fee payments to San Jose to 2% of gross receipts. (Exhibit 242, p. 1.) Staff witness Ramesh Joshi agrees that these increased San Jose franchise fee costs are a normal and reasonable cost of doing business; he concurs with PG&E's calculation of the effect of this arbitration award on the Electric and Gas Department franchise factors, and he agrees that PG&E should recover these increased costs for 1984 and 1985. (Exhibit 253, p. 1-RJ.)

As a result of the same arbitration decision, PG&E also will have to pay San Jose increased franchise fees associated with year 1983. These 1983 franchise fees will not be paid until March 1984, the spring of the test year. PG&E witness Hegler estimates that the additional payments will total \$2.294 million for the Electric Department and \$1.063 million for the Gas Department. PG&E seeks to amortize these costs in equal amounts over the two-year test period (1984-85). (Exhibit 242, p. 2.)

Staff witness Joshi testified that in PG&E's last two general rate case decisions (D.91107 and D.93887) the Commission permitted PG&E to amortize during the test period increased franchise liabilities resulting from litigation and related settlements ocurring prior to the test year.

Staff argues that in D.91107 dated December 19, 1979, the Commission included in rates costs related to higher franchise fees for the test year and a prior year (1979) on the basis of a Superior Court decision in favor of the County of Santa Cruz which sought to include additional costs and revenues in the franchise fee gross revenue calculation. (Opinion No. 49749, Santa Cruz Superior Court, April 17, 1978.) That Court order was appealed by PG&E but no appellate decision was ever rendered, as PG&E settled the case on appeal with the County of Santa Cruz. However, as noted by the Commission in D.91107, it was a feature of the Court decision that PG&E had underpaid fees for years prior to 1979, and the PG&E was ordered to pay those back fees. (2 CPUC 2d 596 at 620.) The settlement, which the Commission indicated was "in lieu of the court's original judgment," inherently related to those years prior to 1979 as well as to current and future fees.

At the time the Commission was deciding test year 1980 expenses for PG&E, the Commission was well aware that it was dealing with a settlement agreement related to a prior period, 1979. We stated in D.91107:

> "By letter dated September 28, 1979 this Commission has been informed that the utility has entered into a negotiated settlement in the Santa Cruz County franchise case. The settlement provides for a \$300,000 lump sum payment in lieu of the court's original judgment of \$650,000 and an agreement that franchise fees, beginning with the payment for 1979, shall be calculated without excluding miscellaneous revenues and without deducting the cost of purchased gas and electricity in the formula. No agreement has to date been negotiated with the other counties involved in this dispute.

> However, it is reasonable to conclude that PG&E for the year 1979 and subsequently will incur the higher tax. We will, therefore, adopt this higher franchise tax rate for the test year 1980 and amortize the increased expenses for 1979 over the 2-year period 1980-1981." (2 CPUC 2d 596 at 620.)

Staff further agrees that amortization of additional back franchise fees were granted PG&E in the 1982 test year general rate case. However, staff argues that the Commission did not address the issue specifically in D.93887. These fees were related to fees owed to Santa Cruz and other counties arising out of the identical recalculation of fees which was at issue in the Santa Cruz lawsuit.

Staff views the Santa Cruz situation as fundamentally different from the fee increase achieved by San Jose. First, no court order exists requiring PG&E to pay San Jose franchise fees for a period of time. There is no allegation that previous fees have been miscalculated. San Jose is one of the few cities in PG&E's service area with a determinate franchise, and at the renewal time, it obtained a new and higher franchise rate. This rate was not reached by agreement between PG&E and San Jose, but by arbitration, which is specified as the means of resolving such disputes in the San Jose franchise agreement. Staff notes that the arbitration agreement only specified a higher rate at which future fees would be calculated. It did not recalculate the fees owed based on the previous rate.

Staff further argues that the court-ordered settlements cover the manner of calculating franchise fees under then-existing rates, whereas, the San Jose arbitration settlement at issue in this proceeding only concerns the rate. Staff considers this difference significant.

Further, in the view of the staff, the San Jose back franchise fees are no different than any PG&E expense which changes unexpectedly during the test year or attrition year.

Staff recognizes that where such court-ordered changes in the <u>manner</u> of calculating fees occur, especially when PG&E is held liable by the courts for past fees that were underpaid, the utility should recover those unexpected costs. Staff acknowledges that this would be true even if the systemwide impact of such a court decision were realized through settlements between the cities and PG&E, as was the case in the Santa Cruz litigation.

As a matter of policy we see no basis to distinguish arbitration settlements from court-ordered settlements for purposes of considering the appropriate ratemaking treatment of prior expenditures. We note that neither the Santa Cruz nor the Sacramento situation, which we will discuss next, involve clear-cut court decisions, but negotiated settlements and tentative decisions.

However, we do believe it reasonable to distinguish between a change in the manner of calculating the franchise fee and a change in the franchise fee rate itself. We agree with our staff that a change in the rate itself, as is the case here, which results in an increase in expense to PG&E, is no different than any other change in expense, upwards or downwards, that occurs during a test period.

We therefore conclude that PG&E should not be permitted to recover the additional expenses for franchise fees owed to San Jose which were incurred outside and prior to the current test period. In our view recoupment of increased expenses incurred in 1983 violates basic principles of test year ratemaking.

We dealt with this very same issue in D.83-05-060, dated May 18, 1983. In that decision we denied PG&E's application which sought offset ratemaking treatment in its ECAC account for these identical franchise fee expense increases. In its application, PG&E itself recognized that "under [PUC] ratesetting procedures, the incremental increase in franchise fee expense would ordinarily not be recognized until [the PUC] next issue[s] a general rate decision." (Mimeo. at p. 2)

Our denial of PG&E's request was based on our adherence, after careful consideration, to test year ratemaking principles. We rejected PG&E's request which we interpreted as a first and precedential step which could eventually lead to balancing account ratemaking treatment for any incremental increase in expense beyond the level set during a specific test period. (Mimeo. at p. 4.) We further observed that by setting franchise fee expense in general rate proceedings and allowing for upward adjustments over the test year, we provide the utility with an incentive to bargain hard with the cities to minimize such expense.

Moreover, we stated that even if we were to consider the incremental increase, PG&E's proposal to recoup unanticipated franchise fee expense increases failed to consider offsetting expense reductions in other areas of utility operations. Any review of a single element without review of the remainder would only serve to distort the relationship among elements and conceivably the entire revenue requirement (see also D.83-12-002 issued December 7, 1983).

Lastly, we recognized the minor nature of this incremental expense change, even assuming no areas of offsetting expense savings, which would have little impact on the company's authorized return.

Notwithstanding our recent decision, PG&E in effect has renewed its request for balancing account ratemaking treatment for an increase in one expense beyond what was contemplated in its last general rate case. Moreover, PG&E seeks to retroactively recoup unanticipated expense incurred in 1983.

For the same reasons we rejected PG&E's request in D.83-05-060, we deny the request again.

(2) <u>Sacramento County</u>

The second area where there is disagreement between staff and PG&E concerns a tentative court decision.

On May 6, 1983, in Opinion No. 272188, the Superior Court of Sacramento County issued its notice of tentative decision regarding Sacramento's lawsuit against PG&E concerning franchise payments. The court found that PG&E should include its interdepartmental sales in the calculation of "gross receipts" for the determination of its franchise fees under existing franchise fee rates.

PG&E faces an estimated increase in Sacramento franchise payments in 1984 of $358,205 for the Gas Department and $98 per year for the Electric Department. In addition, PG&E may be liable for prior payments back to 1973 in the amount of $1,810,059 and $552 for the Gas and Electric Departments, respectively (Exhibit 242, p. 4). These sums exclude any mandated interest charge on the final payments.

Actual liability is uncertain until a final Superior Court decision is issued and PG&E exhausts its legal appeals. In response to this uncertainty, PG&E proposes that the Commission authorize the establishment of a balancing or memoradum account that would be used to accumulate whatever liabilities finally result from this litigation, and that this amount be amortized in a future test year general rate case decision.

Referencing the Commission's treatment of the Santa Cruz franchise fee settlements in D.91107 and D.93887, staff witness Joshi agreed that PG&E should be allowed to recover franchise fee payments associated with years prior to the test year once a final court decision is rendered or PG&E has negotiated a settlement with Sacramento. Furthermore, Joshi agreed that settlements with other governmental entities based on the Sacramento decision precedent should be recoverable from ratepayers in future general rate applications.

However, the staff's position is that balancing or memorandum account treatment for any liabilities that may result from the Sacramento litigation is unnecessary since the exact liability of PG&E is uncertain at this time as the Superior Court of Sacramento has issued only Notices of Tentative Decision in the case, not a judgment. Staff submits that so long as the right to recover franchise fees related to such litigation is not an issue between the staff and the utility, they can reach agreement on the appropriate ratemaking treatment in the next general rate case.

We agree with staff that there is no need to establish a balancing account for franchise fees related to litigation of franchise fees; however, PG&E should be assured of recovering all such reasonably incurred expenses.

We insist that PG&E continue to take an aggressive stand to keep franchise fees to a minimum. There should be no disincentive for PG&E to contest the efforts of governmental entities to increase franchise fees.

We distinguish our treatment of these fees from the San Jose fees on the basis that, in this case, PG&E allegedly mistakenly calculated under then-existing franchise rates the fees owed in prior years because it omitted revenues from inter-departmental sales. In the San Jose case, the dispute was over the level of the rate itself, not the way in which PG&E calculated it. In our view, the latter situation is no different than increases that occur in any expense category due to unanticipated changes either within or beyond the control of the utility (e.g. increased maintenance expense due to unexpected storm damage). Under test year ratemaking such increases are not recoverable, as we explained above.

Accordingly, PG&E may accrue the Sacramento costs in a memorandum account for review for reasonableness in its next general rate case proceeding.

12. Edison Electric Institute (EEI) and American Gas Association (AGA) Dues

The Commission staff has excluded from its estimates of administrative and general expense $345,000 relating to dues to the EEI and $267,000 relating to the AGA. The staff witness based the exclusion of these dues upon Commission policy as announced in the most recent general rate cases for Edison and Southern California Gas Company (D.82-12-055, and D.82-121-054, respectively).

Upon cross-examination staff witness Ramesh Joshi indicated his personal belief that there is sufficient evidence of a benefit to the ratepayers from PG&E's membership in these two associations to allow the dues to be included in rates. (Tr. p. 9234; 9236.) He further stated that if the Commission were convinced by the evidence presented of the existence of such a benefit, he would recommend the inclusion of such dues in rates. The staff witness did, however, indicate that any such allowance should be reduced by approximately 25% of the total dues in order to exclude a component of expenses for legislative and regulatory lobbying expenses in much the same way that the Commission had treated these type of EEI and AGA expenses in the past. (Tr. p. 9571.)

a. EEI

EEI presented Exhibit 185 and testimony, through its witness Dr. Douglas Bauer, in support of PG&E's request for recognition of the portion of EEI dues not related to lobbying activities.

EEI argues that EEI dues produce direct benefits to PG&E's ratepayers and are therefore reasonable and recoverable operating expenses. EEI submits that by far, the bulk of its activities center upon traditional trade association functions--collecting, developing, analyzing, and disseminating information on virtually every phase of generation, sale, distribution, and use of electricity --and on activities directed at improving utility performance, and thereby benefiting ratepayers, in areas where expenses of a utility are traditionally considered a recoverable cost of service.

EEI emphasizes that it is not primarily a promotional organization, and that only a small portion of EEI's dues are dedicated to lobbying or legislative activities. According to EEI, in terms of total resource allocation, it devotes over 86% of its budget resources to activities that are unrelated to lobbying. In fact, EEI contends that legislative activities, which include lobbying and a variety of broadly supportive activities, make up only 14% of EEI's budget and over 72% of its budget is allocated to activities that have absolutely nothing to do with promotional, legislative, or even regulatory activities. EEI submits that only 3% of its budget applies to face-to-face lobbying as it is traditionally defined. EEI further contends that none of its budget is spent on advertising, because the Media Communications Program, funds for which are merely administered by EEI, is wholly separately funded and is not supported through EEI dues. The remaining resources, amounting to more than three-quarters of EEI's budgeted activities, support the core of EEI's continuing programs.

EEI's witness pointed out that PG&E is an active participant in EEI programs. PG&E employees participate extensively on various EEI committees and task forces.

Specifically, EEI argues that its programs, activities, and publications result in numerous direct and indirect savings for PG&E

and its ratepayers through reduced operating costs, increased efficiency, and the elimination of duplication of services. In addition, the exchange of information fostered by EEI and other EEI activities directly benefit PG&E and its ratepayers in ways which may be difficult to quantify, but which are no less significant.

In quantifying the savings achieved for the ratepayer, EEI believes that PG&E has reduced its annual operating costs by millions of dollars as a direct result of EEI's programs and activities, which in turn has helped reduce the rates paid by PG&E's customers. EEI cites many examples of EEI-sponsored programs that it believes have each saved PG&E's ratepayers specific and substantial dollar amounts. For example, EEI points to its Postal Affairs Task Force (a joint project with the AGA) which has successfully procured discounts for presorted, first class mail, saving PG&E and its ratepayers $1,400,000 annually for mailing utility bills.

EEI argues that these quantified savings from EEI activities, which are passed on directly to ratepayers, far exceed PG&E's annual EEI dues. Moreover, these savings represent only a small part of the overall benefits that PG&E and its ratepayers receive from membership in EEI. EEI further argues that EEI and PG&E testimony identifies numerous examples of other benefits which while difficult to quantify are nonetheless significant. For instance, by participating in EEI's Prime Movers Committee, PG&E employees are able to exchange information with over 200 EEI members concerning operation of utility equipment. The contacts developed through this committee on numerous occasions has facilitated the procurement of replacement parts for turbine generators used by PG&E's Steam Generation Department. Each such event shortens the downtime of malfunctioning equipment, enhances equipment efficiency, and saves PG&E thousands of dollars.

b. AGA

AGA presented comparable testimony through its witness Richard R. Kolodiej in support of PG&E's request for recognition of the portion of AGA dues not related to lobying activities.

According to AGA, membership benefits PG&E and its customers in two basic ways: (1) by helping PG&E improve its local policies and procedures in all areas of its operations through a number of programs that facilitate the exchange of information among member companies and its customers; and (2) by undertaking projects collectively or on a national level that would not be feasible or cost effective for a single utility to undertake on its own. (Exhibit 186.)

AGA agrees that many of its activities have benefits that are not easily quantifiable in monetary terms. However, AGA argues that each of its over 1,000 activities in some way contributes to improving efficiency and effectiveness. Further, since many of its activities are directed at improving the safety of gas utility operations, AGA submits, the benefits are difficult to quantify but are of great value to consumers and the utility.

AGA notes that it annually undertakes hundreds of projects and programs related to all areas of gas utility operations. The decision as to which projects and programs will be pursued are made by the members of AGA's 90 committees and their subcommittees. These committees are comprised of almost 4,000 member company employees; it is under the direction of those committees and those employees of member companies that activities are selected to be performed. During cross-examination of the AGA witness, many specific examples of these programs and their benefits were discussed with respect to each of AGA's major functional areas.

AGA further notes that it acts as a clearinghouse for information on operating and engineering techniques that are both more effective and less costly than existing ones. For example, as stated in AGA's testimony, at one meeting of AGA's Compressor Committee, one utility described the use of an inexpensive pressurized plastic pipe fire detection and shutdown system. The PG&E engineer on that committee brought the concept back to his supervisor, and the system has now been installed in four of five PG&E compressor stations at a very low cost. According to PG&E, on two occasions these systems have successfully prevented major fire damage to unattended compressor stations by shutting them down after a fire had started.

AGA argues that through this type of information exchange, gas utility engineers can easily, quickly and in a timely manner keep abreast of the state-of-the-art in gas engineering practices, procedures, tools and materials. Further, by incorporating this information into reference manuals and texts (such as the Gas Engineer's Handbook), AGA acts quickly to make these state-of-the-art practices and tools standard operating procedure for the industry. AGA argues that the aggregate benefit to the gas industry of the cost savings alone resulting from these many (frequently incremental) improvements is in the millions of dollars annually.

AGA next points to the benefits the ratepayer derives from its Conservation and Appliance Efficiency Programs.

AGA testified that it undertakes a wide range of activities directed at improving the efficiency and operation of gas appliances and equipment and ensuring that gas consumers are aware of the cost savings that can result from utilizing these newer devices as well as other conservation measures.

AGA notes that it also works closely with the nation's model code organizations to ensure that, as appliance technology changes, the model codes (which are used by the 40,000 political jurisdictions throughout the country) are revised without unnecessary delay.

AGA testified that there are many other programs--including appliance certification and information distribution that AGA undertakes to facilitate the development and use of more efficient, safer appliances. Like EEI, AGA cites specific examples of efforts and programs which it believes have led to specific and substantial quantifiable savings.

In D.82-12-055 and D.82-12-054, we did not allow expenses for dues paid to EEI and AGA, respectively, because of the absence of a convincing showing that direct benefits from this expense accrue to ratepayers. We conclude that both EEI and AGA did provide a convincing showing in this proceeding that benefits accrue to the ratepayer through PG&E membership of their respective organizations. The testimony shows that EEI and AGA activities help PG&E decrease costs and increase operational efficiency in many areas. Also, on the basis of the testimony, it is reasonable to conclude that EEI and AGA membership by PG&E does produce some tangible benefits for the ratepayers at a reasonable cost. Accordingly, we find it reasonable to allow ratepayer funding of a portion of these expenses. We will allow EEI and AGA dues as a ratemaking expense less 25% for lobbying activities which do not benefit the ratepayer.

13. <u>Productivity</u>

The staff made adjustments throughout PG&E's test year expense estimates to reflect additional productivity allegedly not reflected in the utility's estimates. This issue permeated the Results of Operations phase of this proceeding and was vigorously contested by PG&E.

The cornerstone of staff's additional productivity adjustment is the management audit report prepared by the firm of Cresap, McCormick and Paget (CMP). The total recommended disallowance is $408,000 for the Electric Department.

Staff argues that faced with indications in the CMP report that PG&E has achieved improvements in productivity and has room for more improvements, the staff believes it has a responsibility to take those improvements into account. Staff submits that if that requires the use of a number of rough estimating techniques in order to make an adjustment, then that is what must be done. Staff contends it would be irresponsible on its part to ignore potential increases in productivity simply on the grounds that a statistically valid measurement is not available at the present time. In view of the varying levels of productivity improvement noted in the CMP report and PG&E's own calculations, staff argues that the use of a 4% figure for only the labor components of those accounts associated with crew work is a conservative adjustment.

Staff further argues that a reduction to reflect productivity savings is all the more appropriate because PG&E has not made any specific reduction to its labor estimates due to productivity, and maintains that productivity increases are embedded in the averages and trends used to estimate expenses. Staff rejects the notion that any historical or embedded productivity can accurately reflect changes in productivity in the future. According to staff, the productivity discussed in the CMP audit for transmission expenses is an appropriate example. The productivity measurement systems which are just being implemented and tested have not been having an effect on historical expense levels. Therefore, staff contends that they should produce an increase in productivity beyond that which will be included in any trend line or average based on historical expense levels. Staff submits that unless a specific adjustment is made to reflect that increase in productivity, the expense levels derived from trends or averages will overstate the utility's actual expenses.

PG&E argues that its continuing and vigorous efforts to improve efficiency and productivity should not be used as an excuse to ignore legitimate cost increases the utility will be facing in the test period. According to PG&E, the staff has inconsistently and unfairly used productivity as an excuse to deny realistic expense estimates.

PG&E notes that it is committed to improving the efficiency and productivity of its people and operations. Recognizing the Commission's intense interest in this vital subject area, PG&E's senior vice president - operations, E. B. Langley, Jr., sponsored Exhibit 4, which presented in considerable detail examples of PG&E's productivity and efficiency efforts both historical and planned.

PG&E submits that a review of this material demonstrates that the utility is seeking productivity and efficiency improvements in all aspect of its operation. PG&E notes that the inter-utility comparisons contained in this exhibit show that in the crucial measurements of Electric Transmission Maintenance and Operations Expenses per Customer, Gas Distribution Maintenance and Operations Expenses per Customer, and Electric and Gas Administrative and General Expenses per Customer, PG&E has consistently performed equal to, or better than the industry, in terms of average levels of expenditures per customer.

In addition to PG&E witness Langley's overview exhibit and testimony, PG&E notes that each of its results of operations witnesses addressed the productivity and efficiency improvements in his or her areas of responsibility. PG&E contends that its estimates of the costs it will be facing in the test period include the effects of productivity and efficiency improvement.

The original CMP Management Audit (Audit) was submitted to the Commission on June 1, 1980. The Audit contained 131 recommendations. PG&E agreed with 121, partially agreed with 6, and disagreed with 4 of the recommendations. Since that Audit, PG&E contends it has diligently sought to implement the recommendations, and has reported its progress regularly to the Commission.

In D.92940, dated April 21, 1981, the staff was required to review these 10 areas of partial agreement or disagreement. Staff auditor D. F. Butler performed such a review and gave PG&E a clean bill of health.

PG&E's chairman, F. W. Mielke, Jr., in order to ensure that the utility was obtaining the maximum benefit from the Audit, decided to have CMP perform an evaluation of the progress PG&E had made in meeting the Audit's recommendations. A copy of that report, entitled "Evaluation of PGandE Progress In Implementing Selected Recommendations From The Operations And Management Audit", was provided to the staff on January 27, 1983, and PG&E's complete response to the findings of that report were provided on March 18, 1983. There were 41 findings with which the utility agreed, 26 where there was partial agreement, 2 where there was disagreement, and 2 where a decision had not yet been reached. CMP informed PG&E in its covering letter of December 10, 1982, that "[t]aken as a whole, the results of the evaluation indicated that PGandE has accomplished very significant improvements over the past two years."

PG&E contends that staff witnesses, unable to justify a specific cost denial, assert that unspecified "productivity" increases will obviate the need for certain expense increases in the test period.

Further, PG&E takes strong exception to staff's productivity adjustment to the attrition allowance. Staff witness DeBerry assumed that in the attrition year 1985 activity level increases will be completely offset by productivity increases. At the same time, DeBerry agreed that the staff estimates for test year 1984 show activity level increases exceeding productivity increases. He further agreed that activity level growth exceeded productivity increases in the 1982 test year decision and that the Commission based on a staff recommendation, assumed that activity level increases would be precisely offset by productivity increases in attrition year 1983.

PG&E argues that the effect of assuming that productivity increases will precisely offset activity level growth only in attrition years (1983 and 1985) is to adopt estimates that are saw-toothed because growth is only recognized every other year. According to PG&E this result is patently wrong because it is based on one, the other, or both of the following assumptions: (1) activity level growth is less in attrition years, or (2) productivity is higher in attrition years.

We reject PG&E's argument that activity growth be recognized in the attrition year. As we see it, this will lead to further extension of an already long-drawn out general rate case proceeding. If we were to consider growth increases, we would also have to consider offsetting productivity increases and program changes which occur in the attrition year. To do this, we would end up with a two test year rate case. We simply do not have the staff resources to handle this.

Turning to staff's adjustment for additional productivity, we will examine the adjustments on an account-by-account basis. But we should observe that it certainly is not our intention to penalize a utility for achieving productivity gains. We will not reflect unsupported productivity assumptions to arrive at a quota of expense disallowance.

B. Electric Department
Results of Operations

1. Revenues

With the exception of one item, staff and PG&E reached a stipulation regarding sales, revenues, and jurisdictional allocations. The item at issue relates to Resale-Nonfirm Energy Purchases. Since PG&E's estimate lacks confirmation by its resale customer, we will adopt the staff estimate for this item which is based on average year hydro conditions. (Exhibit 258, p. 4-3 revised.)

The margin, based on late-filed Exhibit 262, Table 2, is $2,124,323. The adopted sales and revenue estimates are set forth in the following tables.

Pacific Gas and Electric Company
Electric Department
COMPANY SALES AND LOADS
Test Year 1984

(Millions of Kilowatt Hours)

Description	PGandE	Staff	Adopted
Residential	19,743	19,743	19,743
Light and Power			
Small	4,792	4,792	4,792
Medium	13,710	13,710	13,710
Large	14,570	14,570	14,570
Total Light and Power	33,072	33,072	33,072
Public Authority	297	297	297
Agricultural	3,454	3,454	3,454
Street Lighting	360	360	360
Railway	245	245	245
Resale	190	1,235	1,235
Interdepartmental	139	139	139
Total Company Sales	57,500	58,545	58,545
Other Company Loads			
Electric Department Uses	26	26	26
Losses & Unaccounted for	6,032	6,032	6,032
Total Other Loads	6,058	6,058	6,058
Total Company Sales and Loads	63,558	64,603	64,603

Pacific Gas and Electric Company
Electric Department

ESTIMATED REVENUES AT PRESENT RATES*
12-MONTH PERIOD ENDING DECEMBER 1984
Test Year 1984
(000's Omitted)

Class of Service	PGandE	Staff	Adopted
CPUC JURISDICTIONAL			
Residential			
Tier I	$ 439,549	$ 439,549	$ 439,549
Tier II	200,737	200,737	200,737
Tier III	122,571	122,571	122,571
AR - 1	7,197	7,197	7,197
Total Residential	$ 770,054	$ 770,054	$ 770,054
Light and Power			
Small	$ 213,554	213,554	$ 213,554
Medium	514,908	514,908	514,908
Large	477,343	477,343	477,343
Total	$1,205,805	$1,205,805	$1,205,805
Public Authority			
DWR	$ 0	$ 0	$ 0
Other	8,461	8,461	8,461
Total	8,461	8,461	8,461
Agricultural	$ 125,078	$ 125,078	$ 125,078
Street Lighting	38,688	38,688	38,688
Railway	7,166	7,166	7,166
Interdepartmental			
Construction	3,758	3,758	$ 3,758
Operation	1,326	1,326	1,326
Subtotal	2,160,336	2,160,336	$2,160,336
Other Operating Revenues	$ 17,142	$ 17,142	$ 17,142
Total CPUC Base **	2,177,478	2,177,478	$2,177,478
FERC JURISDICTIONAL			
Resale	$ 27,089	$ 31,557	$ 31,557
Other Operating Revenues	20,438	20,438	20,438
Total FERC	$ 47,527	$ 51,995	$ 51,995
Total **	$2,225,005	$2,229,473	$2,229,473

* Rates in effect 10/19/83 for CPUC per Exhibit 262 and 4/1/83 for FERC.

** Excludes CFA, RCS, AER, and SFA revenues.

2. Production Expenses

Production expenses include all electric power generation expenses with the exception of expenses related to ECAC-related fuel and purchased power. Non-ECAC fuel-related expenses are included.

Before reviewing the numerous Steam and Hydraulic Power Generation issues, we will address the Spent Nuclear Fuel question and the estimate of Cost of Fuel, Water, and Purchased Power.

a. Spent Nuclear Fuel

Staff witness K. P. Coughlan, after reviewing PG&E's Exhibit 207 concerning Humboldt Bay Unit 3, and after receiving a letter from PG&E concerning the details of the utility's Humboldt spent fuel contract with the Department of Energy (DOE), agreed with the utility's estimate of the cost of the contract. He agreed that the contract calls for a payment of $3,887,000 by June 30, 1985, and that taking the time value of money into account, PG&E should be allowed to recover one-half of $3,648,000 in 1984 and in 1985.

We will reflect this latter amount in our adopted results of operations.

b. Non ECAC/FCA Cost of Fuel, Water, and Purchased Power

The ECAC instituted by the Commission allows the utility to recover its fuel-related expenses through a balancing account. The expenses not recovered through ECAC are (a) the costs associated with operational and maintenance payments to the Irrigation Districts and Water Agencies; (b) the costs associated with the purchase and impoundment of water for power and PG&E's expenses for weather modifications; (c) the portion of purchased power expenses which are allocated to FERC jurisdictional sales which are not recoverable under the FERC Fuel Clause.

Staff and PG&E reached agreement on these expenses (Exhibit 258, p. 4-5 revised), which will be reflected in the adopted results of operations.

c. Other Production Expense

These expenses include the costs associated with the operation and maintenance of the utility's electric generating plants. They do not include fuel.

In 1981 dollars, PG&E's estimate of total Other Production Expenses of $163,107,000 exceeds the staff's estimate of $147,092,000 by $16,015,000. The reasons for the difference are set forth below.

Escalation of Historical Data	$ 360,000
Deferred Maintenance	5,368,000
Reliability Improvements	4,825,000
Estimating Techniques	5,462,000
Total	$16,015,000

The first two issues are discussed in the policy section of this opinion and will not be addressed in detail again here. As discussed in the policy section, our adopted results will reflect use of the WPI-IND for escalation of historical data, and we will adopt the staff recommendation to deny all requests for deferred maintenance.

(1) Reliability Improvements

This program involves a series of planned expenditures to upgrade the utility's generating plant. PG&E proposes to spend $9,650,000 on this program in 1984, and $8,750,000 in 1985.

Following field inspections of the plant included in this program, staff witness Randhawa concluded: (1) the performance of PG&E's fossil-fired plants has been on the decline since 1977; (2) the implementation of the Reliability Improvement Program will "enhance the system integrity" and "keep the operating efficiency of the system from deteriorating"; (3) it will reduce costs due to more efficient operation; and (4) PG&E's system reserve margin is expected to be high in 1984, making that year a good time to implement the program.

Staff witness Randhawa recommended that the Reliability Improvement Program be undertaken. However, he concluded that PG&E's program is too ambitious and that the utility should receive only half the amount requested.

Staff argues that PG&E never demonstrated a specific time table to indicate exactly how all the maintenance activities contained in the program could be performed within two years, and in fact indicated in some workpapers that some of the work would take at least three years. In the opinion of the staff witness it would not be possible for the utility to overhaul all its plants during this period of time in order to include the reliability improvements in the repairs that would be made during such overhauls.

We note that the PG&E witness testified that a program to implement these improvements is in place. The staff agrees that the proposed expenditures are cost-effective, and that 1984 would be a good time to begin these increased maintenance activities. Also, we are concerned about the deteriorating heat rates of PG&E's aging oil and gas fired steam generating plants. It was estimated that 1% improvement in the heat rate equates to $12 million in annual fuel savings. We strongly support the implementation of the proposed program. There is no doubt as to its need and value to PG&E's aging system.

However, we agree with staff that the PG&E program appears too ambitious to allow prudent expenditure of the entire request within the test period. The requested $9,650,000 would be in addition to the usual maintenance allowances. We will allow staff's recommended $4,825,000 in the test year.

We expect PG&E to provide a separate exhibit, in its next general rate case proceeding, setting forth details of the improvements completed, actual expenditures and a cost-effectiveness analysis including improvements achieved in heat rates. Also, we expect staff to thoroughly review the expenditures for this program. We intend to carefully examine this matter in PG&E's next general rate case proceeding and will not hesitate to penalize PG&E if there is evidence to conclude that these funds have been imprudently spent.

(2) Unforeseen Expenses

There is an allowance of $10.2 million in both the test year and the attrition year for unforeseen expenses. Unforeseen expenses include the cost of forced outages and unplanned maintenance not included in P&GE's maintenance budget for the year. For example, if a turbine rotor throws a row of buckets and the unit is forced out of service for repair, the cost of this repair is considered an unforeseen expense. Because of the number of units involved and the age of these units, there are significant expenditures each year in this category.

PG&E's witness explained that unforeseen expenses have increased exponentially over the last five years and that a trend based on recorded data for these costs would soon reach infinity. To resolve this problem, unforeseen expenses were removed from the recorded power production maintenance expense data, so that this category of expense could be considered separately. A similar approach was used in Edison's last general rate case--see Class III Overhaul Expenses, mimeo. p. 41, D.82-12-055.

The utility used an average of its unforeseen maintenance expenses for the period 1977 to 1981 to arrive at the estimate for the test year period. The staff recommendation is to allow the unforeseen expense request for 1984 and for 1985, but that, in anticipation of a reduction in unforeseen expenses in 1985 due to reliability improvements the utility intends to make, the utility be required to provide a report detailing to the Commission what improvements have been made and what their dollar impact has been upon unforeseen expenses. As a result of this report the staff witness also recommends that the Commission should provide for an adjustment in the 1986 test year to offset against 1986 test year expenses any unspent monies which had been allocated for unforeseen expenses in either the test year or the attrition year.

Staff does not address the question of whether the utility will be allowed to recover, in its next general rate case, any funds spent on unforeseen expenses which exceed the amount allowed in rates. Apparently, staff does not consider unforeseen expenses to be a "two-way street."

The staff recommendation is denied. We do not intend to open the door to retroactive recovery for unexpected expenses incurred prior to the test year.

We should explain that our unwillingness to adopt the staff's recommendation is based on the same policy which underlies our position on deferred maintenance. For the test year, we adopt the most reasonable estimate based on the record in the proceeding. If the utility and the staff both underestimate test year expenses, for whatever reason, we will not in a subsequent general rate case proceeding allow recovery for such prior underestimated expenses. If the test year estimate is higher than the actual expenses, the stockholder keeps the benefit. On the other hand, if the utility has to incur expenditures greater than allowed for the test year the stockholder has to make up the difference. This is the basic concept of test year ratemaking. Also, we should add that in the latter situation, we will not permit the utility to defer maintenance for the reason that the test year expense level will be exceeded and the additional expenditure will reduce stockholder profit.

In summary, we will adopt PG&E's estimate of unforeseen expense.

(3) <u>Estimating Techniques</u>

The staff witness agreed with PG&E's linear trend estimating technique as long as the coefficient of determination (R-squared) shows a value greater than 0.6 and the T-statistic was at least 2.0. If the R-squared was less than 0.6, the staff used a five-year average (1977-1981) or the end-of-year recorded expenditures for 1981. The staff witness treated labor and nonlabor estimates separately. We note that historical expenses used to estimate test period expenses are in constant dollars, so the estimating techniques do not attempt to capture the effect of inflation. Inflation is treated separately through use of escalation factors.

PG&E argues that the staff witness did not check the R-squared for a combined labor and nonlabor estimate. PG&E contends that if he had he would have found accounts where the combined R-squared exceeded 0.6. We are not convinced by PG&E's argument. The mere fact that the combined accounts may yield an R-squared in excess of 0.6 is not in itself conclusive that we should accept the estimate. While an argument may be made for combining labor and nonlabor in certain accounts, we prefer to see these handled separately.

Also, we are not prepared to automatically accept either PG&E's or staff's estimates for any account, labor, nonlabor or both combined, simply because the R-squared exceeds 0.6 and the T-Statistic is at least 2.0. There are other considerations which override the mechanical application of statistical techniques.

Turning to staff's use of a five-year average in instances where the R-squared is less than 0.6, PG&E argues that since a five-year average has a coefficient of determination of zero, it is less preferable than a linear trend that has a coefficient of determination somewhere between 0 and 0.6, particularly when the reasons for the lower coefficient can be specifically identified. Furthermore, the mid-point of a five-year average ending in 1981 is 1979, which is a point in time 5 years before the test year. With aging plant, maintenance costs generally rise. According to PG&E it simply does not make sense to determine maintenance expenses for the test year based on historical averages.

PG&E notes that the utility and staff have used averaging techniques in past rate cases. In D. 82-06-020, dated June 2, 1982, in OII 89, the Commission noted the deficiency of these estimates: "However, all parties agree that since actual maintenance expenses have consistently exceeded projected expenses, maintenance practices and the methodologies used to project maintenance costs should be reexamined." (Mimeo. p.6.)

We will not adopt a blanket approach to the estimating technique issue. We will consider each account individually to arrive at an adopted test year level of expenditure.

(4) Review of Specific Accounts

In general, we do not discuss differences due to escalation of historical data, deferred maintenance, or the Reliability Improvement Program. The adopted amounts in each account reflect the earlier resolution of these issues.

Account 502
Steam Expenses

PG&E requested $13,496,000; the staff recommends $12,857,000, leaving $639,000 at issue. The primary cause of this difference is the staff's use of a 5-year average to determine both labor and nonlabor estimates. PG&E employed a linear trend.

The difference due to estimating technique comprises $80,000 in labor and $456,000 in nonlabor expense. We note PG&E made an upward adjustment in 1984 of $1,339,000 for labor and $517,000 for nonlabor to cover expenses not included in the trend. Also, we note staff recommends some reduction in the labor increases requested by PG&E. Based on prior recorded expenses we find the increase requested by PG&E for labor to be excessive. Accordingly, we will adopt the staff's adjustment for labor. Regarding the nonlabor portion, we conclude that an average will not adequately reflect changes in operating needs; therefore, we will adopt PG&E's estimate for the nonlabor portion.

Account 505
Electric Expenses

PG&E requested $31,541,000; the staff recommends $28,343,000, leaving $3,198,000 at issue. The labor portion of the difference amounts to $1,000 and the nonlabor portion $3,197,000. The primary difference between the utility and the staff estimates involves the staff's use of a five-year average to forecast the nonlabor component of this account as compared to the utility's use of trending.

We note that the nonlabor items include expenses for lubricants and control system oils, generator cooling gases, circulating water purification supplies, cooling water purchased and motor and generator brushes.

We note that staff did separately allow $15,620,000 for hydrogen sulphide abatement expenses at the Geysers Power Plant. We believe PG&E's estimate to be excessive, since, apart from Geysers, there is little justification for the significant increase sought for 1984 over 1981 recorded levels. We will adopt the staff estimate for nonlabor expense. Also, we will adopt the staff-recommended adjustment of $1,000 for labor expense.

Account 506 Miscellaneous
Steam Power Expenses

PG&E requested $9,912,000, the staff recommends $10,009,000; leaving $97,000 in the utility's favor.

The $97,000 consists of a $2,000 methodological and a $95,000 historical escalation difference. We will adopt the staff methodology for estimating.

Account 535 Supervision
and Engineering

PG&E has requested $1,775,000; the staff recommends $1,734,000 leaving $41,000 at issue.

The primary difference between PG&E and staff is estimating technique. Based on the recorded data, we conclude that the increase requested by PG&E for 1984 is reasonable. We will adopt PG&E's estimate.

Account 538
<u>Electric Expenses</u>

PG&E requested $3,364,000; the staff recommends $3,295,000, leaving $69,000 at issue. The main difference involves the estimating technique issue. Based on recorded expense levels, we conclude that PG&E's estimate for the test year is reasonable. We will adopt PG&E's estimate.

Account 539 Misc. Hydraulic
<u>Power Generation Expenses</u>

PG&E requested $2,506,000; the staff recommends $2,383,000, leaving $123,000 at issue.

The major difference is due to estimating technique in the labor portion of this account. This account covers general clerical work, building service, care of grounds, snow removal from roads and bridges and miscellaneous labor. Based on recorded expenditures, we conclude that the increase requested by PG&E for 1984 is reasonable. We will adopt PG&E's estimate.

Account 537.20
<u>Recreation Expense</u>

PG&E requested $70,000; staff recommends $68,000. Based on the most recent recorded expenditures, we conclude that PG&E's estimate is reasonable and we will adopt it.

Account 537.30
<u>Recreation Expense</u>

PG&E requested $454,000; staff recommends $485,000. The difference is mainly due to estimating technique related to nonlabor expense. Based on the most recent recorded expenditures, we conclude that PG&E's estimate provides for reasonable growth. Therefore, we will not adopt the staff adjustment due to estimating methodology.

Account 546 Supervision
and Engineering

PG&E requested $38,000; the staff recommends $39,000, leaving $1,000 in the utility's favor. The difference is due to estimating methodology. We will adopt staff's estimate since it does provide for some growth.

Account 548
Generation Expense

PG&E requested $213,000; the staff recommends $183,000, leaving a difference of $30,000.

PG&E did not use a linear trend method to forecast these expenses as the trend portrayed an unreasonable growth rate. Due to addition of plant during the historical period 1977-1981, PG&E concluded that a five-year average was inappropriate and used recorded 1981 expenses as a base. We conclude that use of 1981 recorded expense, in this instance, is reasonable. We will adopt PG&E's estimate.

Account 511 Structures

PG&E requested $2,354,000; the staff recommends $1,517,000, leaving $837,000 at issue. The two differences not previously resolved are a mathematical error of $19,000 by the staff, and a difference due to estimating technique of $[illegible],000.

We will reflect the correction for the staff error and will adopt the staff adjustment for estimating technique since the staff estimate provides for reasonable growth after adjustment for deferred maintenance.

Account 512.20 Boilers and
Related Apparatus

PG&E requested $19,110,000; the staff recommends $15,930,000, leaving $3,180,000 at issue. The only issue not previously resolved involves estimating technique--worth $470,000.

We will adopt the staff adjustment for estimating technique since staff's estimate provides for reasonable growth based on the most recent recorded data.

Account 512.30 Boilers Plant Auxiliaries

PG&E requested $10,345,000; the staff recommends $7,931,000, leaving $2,414,000 at issue.

The only difference not previously resolved is estimating technique in the amount of $165,000. We will adopt the staff adjustment since, based on prior recorded data, the staff estimate provides a reasonable allowance for growth.

Account 513.40 Main Turbogenerators and Related Apparatus

PG&E requested $19,111,000; the staff recommends $15,166,000, a $3,945,000 dispute.

The only difference not previously resolved is due to estimating technique, amounting to $1,400,000. Based on the most recent recorded data, we conclude that PG&E's test year estimate is reasonable. We will adopt PG&E's estimate related to the estimating issue.

Account 513.50 Main Turbo-generators Auxiliaries

PG&E requested $9,468,000; the staff recommends $8,791,000, leaving $677,000 at issue.

The difference due to estimating technique amounts to $648,000 in PG&E's favor. Based on 1982 recorded data, we conclude that PG&E's estimates is reasonable. We will adopt PG&E's estimate.

Account 513.60 Accessory Electric Equipment

PG&E requested $3,142,000; staff recommends $2,343,000; leaving $799,000 at issue.

The only difference not previously resolved involves estimating technique and amounts to $1,000 in PG&E's favor. We will adopt the staff estimate since it better reflects the most recent recorded data after deduction for deferred maintenance.

Account 514 Miscellaneous Steam Plant

PG&E requested $2,923,000; the staff recommends $2,940,000, leaving a difference of $17,000 in the utility's favor. Estimating technique accounts for $1,000. We will adopt the staff estimate.

Account 541 Supervision And Engineering

PG&E requested $962,000; the staff recommends $963,000, leaving $1,000 at issue. We will adopt the staff estimate.

Account 542 Structures

PG&E requested $545,000, the staff recommends $469,000, leaving $76,000 at issue. Part of the difference involves estimating technique. We will adopt the staff estimate.

Account 543 Reservoirs, Dams and Waterways

PG&E requested $4,084,000, the staff recommends $3,914,000, leaving $170,000 at issue.

The primary difference involves estimating technique. Based on recorded data, we conclude that PG&E's estimate is reasonable. We will adopt PG&E's estimate.

Account 544.30 Prime Movers and Generators

PG&E requested $2,649,000, the staff recommends $2,714,000, leaving $65,000 in the utility's favor. The main difference is estimating technique.

Based on recorded data, we conclude that PG&E's estimate is reasonable. We will adopt PG&E's estimate.

Account 544.40 Accessory Electric Equipment

PG&E requested $396,000; the staff recommends $422,000, leaving $26,000 in the utility's favor.

The main difference is due to estimating technique. Based on recorded data, we conclude that PG&E's estimate is reasonable. We will adopt PG&E's estimate.

Account 545.50 Miscellaneous Hydraulic Plant

PG&E requested $215,000, the staff recommends $200,000, leaving $15,000 at issue.

The major difference is due to estimating technique. Based on recorded data, we conclude that the utility's estimate is reasonable. We will adopt PG&E's estimate.

Account 545.80 Recreation Facilities

PG&E requested $121,000, the staff recommends $103,000, leaving $18,000 at issue.

The primary differences are the New Projects, amounting to $10,000, and Helms recreation facilities amounting to $5,000. According to PG&E, these expenditures are required by law and they will be increasing each year as new generation facilities are licensed and old facilities are relicensed. We will adopt PG&E's estimate.

Account 552 Structures

PG&E requested $24,000; the staff recommends $17,000, leaving $7,000 at issue.

The staff employed a five-year averaging technique and the utility used a linear trend to estimate 1984 expenses. We will adopt the staff estimate since it provides a reasonable allowance for growth.

The adopted expenses are set forth in the following tables.

Electric Department

NON-ECAC/FCA EXPENSES FOR FUEL,
WATER AND PURCHASED POWER
Test Year 1984
(000's Omitted)

Description	PGandE	Staff	Adopted
Irrigation Districts	$ 9,105	$ 9,105	$ 9,105
Purchased Water	3,033	3,033	3,033
Purchased Power	283	283	283
Total (1984 Dollars)	$12,421	$12,421	$12,421

Electric Department

PRODUCTION OPERATION EXPENSES

Test Year 1984

(000's Omitted)

Account No.	Description	PGandE	Staff	Adopted
	Steam Power Generation			
500	Supervision and Engineering	$ 3,144	$ 3,151	$ 3,144
502	Steam Expenses	13,496	12,857	13,416
505	Electric Expenses	31,541	28,343	28,396
506	Miscellaneous Steam Power Exps.	9,912	10,009	9,914
507	Rents	4,752	4,752	4,752
501	Fuel - Other Expenses	1,603	1,603	1,603
	Total Steam Power Generation	$64,448	$60,715	$61,225
	Nuclear Power Generation			
517	Supervision and Engineering	$ 244	$ 244	$ 244
519	Coolants and Water	22	22	22
520	Steam Expenses	527	527	527
523	Electric Expenses	107	107	107
524	Miscellaneous Nuclear Power Exps.	790	790	790
	Total Nuclear Power Generation	$ 1,690	$ 1,690	$ 1,690
	Hydraulic Power Generation			
535	Supervision and Engineering	$ 1,775	$ 1,734	$ 1,775
537.10	Hydraulic Expense	2,231	2,208	2,231
538	Electric Expenses	3,364	3,295	3,364
539	Miscellaneous Hydraulic Power Generation Expense	2,506	2,383	2,506
540	Rents	2,034	2,034	2,034
537.20	Fish and Wildlife Expenses	70	68	70
537.30	Recreation Expenses	454	485	454
	Total Hydraulic Power Generation	$12,434	$12,207	$12,434
	Other Power Generation			
546	Supervision and Engineering	$ 38	$ 39	$ 39
548	Generating Expense	213	183	213
549	Miscellaneous Other Power Generation Expenses	191	191	191
	Total Other Power Generation	442	413	443
	Total Production Operation Exps. (1981 Dollars)	$79,014	$75,025	$75,792
	Escalation Amounts			
	Labor	8,301	8,199	8,281
	Non-Labor	6,473	3,662	4,142
	Total (1984 Dollars)	$93,788	$86,886	$88,215

Electric Department

PRODUCTION MAINTENANCE EXPENSE

Test Year 1984

(000's Omitted)

Account No.	Description	PGandE	Staff	Adopted
	Steam Power Generation			
510	Supervision and Engineering	$5,411	$5,418	$5,411
511	Structures	2,354	1,517	1,553
512.20	Boilers and Related Apparatus	19,110	15,930	16,025
512.30	Boiler Plant Auxiliaries	10,345	7,931	8,005
513.40	Main Turbogenerators and Related Apparatus	19,111	15,166	16,661
513.50	Main Turbogenerators Auxiliaries	9,468	8,791	8,230
513.60	Accessory Electric Equipment	3,142	2,243	2,338
514	Miscellaneous Steam Plant	2,923	2,940	2,924
514.10	Urban Recreational Facilities	16	16	16
	Total Steam Power Generation	$71,880	$60,052	$61,163
	Nuclear Power Generation			
528	Supervision and Engineering	$57	57	$ 57
529	Structures	45	45	45
530.20	Reactor and Related Apparatus	15	15	15
530.30	Reactor Plant Auxiliaries	57	57	57
531.40	Main Turbogenerators and Related Apparatus	12	12	12
531.50	Main Turbogenerators Auxiliaries	19	19	19
531.60	Accessory Electric Equipment	5	5	5
532	Miscellaneous Nuclear Plant	38	38	38
	Total Nuclear Power Generation	$ 248	$ 248	$ 248
	Hydraulic Power Generation			
541	Supervision and Engineering	$ 962	$ 963	$ 963
542	Structures	545	469	464
543	Reservoirs, Dams and Waterways	4,084	3,914	4,084
544.30	Prime Movers and Generators	2,649	2,714	2,649
544.40	Accessory Electric Equipment	396	422	396
545.50	Miscellaneous Hydraulic Plant	215	200	215
545.60	Roads, Railroads and Bridges	1,012	1,012	1,012
545.70	Fish and Wildlife Facilities	14	14	14
545.80	Recreation Facilities	121	103	121
	Total Hydraulic Power Generation	$ 9,998	$ 9,811	$9,918
	Other Power Generation			
551	Supervision and Engineering	$ 49	$ 49	$ 49
552	Structures	24	17	17
553	Generating and Electric Equipment	1,817	1,813	1,817
554	Miscellaneous Other Power Generation Plant	77	77	77
	Total Other Power Generation	$1,967	$1,956	$1,960
	Total Production Maintenance Expenses (1981 dollars)	$84,093	$72,067	$73,289
	Escalation Amounts			
	Labor	10,034	9,211	9,294
	Nonlabor	7,302	3,648	4,178
	Total (1984 dollars)	$101,429	$84,926	$86,761

3. Transmission Expenses

Electric transmission expenses are those incurred by the utility in operation and maintenance of overhead and underground lines with voltage levels of 50 kV and above. Included in this category are expenses for supervision and engineering, load dispatching, structures, station equipment, rents, and fixed wheeling charges.

PG&E's estimate of total Transmission Expenses of $27,133,000 exceeds staff's estimate of $25,892,000 by $1,241,000. The reasons for the difference between the utility and staff are the following:

Deferred Maintenance	$ 546,000
Estimating Technique	323,000
Productivity Adjustment	61,000
Historical Escalation	199,000
Shift Premiums	112,000
Total	$1,241,000

The following issues are common to many accounts within this functional area: (1) deferred maintenance; (2) estimating technique (trending); (3) productivity adjustments; (4) historical escalation factors. We will discuss deferred maintenance and productivity adjustment before an account-by-account review.

a. Deferred Maintenance

We have previously covered the issue of deferred maintenance in the policy section of this opinion. We will now review deferred maintenance as it relates to Electric Transmission Expenses.

The staff witness recommends disallowance of PG&E's request for deferred maintenance funds based on his interpretation of D.82-12-055, the most recent Edison general rate case decision. This recommendation affects the following accounts: 571.62 Clean Insulators and Bushings; 571.64 Stubbing Poles; 571.66 Pole Treating; 571.71 Paint Poles Towers and Accessories; and 571.72 Other Overhead Line Maintenance.

PG&E argues that it is normal business practice to establish priorities for maintenance dollars. PG&E points out that it does not have unlimited funds; it must set priorities for the funds it has, and the Commission should concentrate on the correctness of the priorities set for these funds.

PG&E further argues that in the area of Transmission Expense there are several programs that PG&E identified as deferred maintenance activities that are better described as new or expanded maintenance programs. According to PG&E the greatly expanded pole treating and stubbing programs and the San Joaquin insulator washing program are examples of these mislabeled programs. PG&E submits that these programs are actually increased efforts to improve the reliability of the utility's transmission system and should be distinguished from what has classically been defined as deferred maintenance.

Staff agrees that Account 571.62 for cleaning insulators and bushings appears to have been inappropriately described as deferred maintenance by PG&E in a data request (Exhibit 164). PG&E witness Nesbit testified that the program really is a new program being increased in scope in order to respond to additional agricultural activity in the San Joaquin Valley. To the extent that the program was not previously scheduled at an earlier time and deferred or reduced in scope for budgetary reasons, staff agrees it does not fall within the category of deferred maintenance. Accordingly, we will reflect the $25,000 associated with this program in our adopted expenses.

Staff argues that the remaining deferred maintenance in the transmission category is classic deferred maintenance and is not by any means related to a new program. We agree with staff.

For the policy reasons discussed previously, we will disallow PG&E's request for deferred maintenance funding in all transmission expense categories, with the exception of the insulator washing program for $25,000 in Account 571.62. The amount disallowed is $521,000.

b. Productivity Adjustments

Staff made a $61,000 adjustment in test year expenses to reflect additional productivity in transmission expenses which the utility allegedly has not reflected in its estimates.

Staff points to the CMP Audit Report (1982) which states that PG&E's productivity measurement system revealed a 5% improvement in productivity over the last 18 months. This program was instituted and pilot tested in one division only. PG&E recalculated this productivity measurement and came up with a 4% improvement for 1982. Accordingly, staff made a 4% reduction to the labor components of all accounts associated with crew work and/or work handled by work orders, which is the area cited by CMP where improvements have occurred. This adjustment affects Accounts 571.62-571.66, 571.68-571.74 and 571.75, 572, and 573.

PG&E argues that the CMP evaluation was flawed and that the assumed productivity increase could not be supported. Also, PG&E further argues that productivity efforts have been ongoing at PG&E for years. Therefore, estimates based on trends automatically reflect the historical productivity efforts. PG&E contends that the staff's 4% productivity assumption ignores this fact and vastly overstates crew productivity improvements.

We note that staff has applied the productivity adjustment only to the areas where CMP has noted additional productivity improvement. We agree with staff that such improvement would not be reflected in the trend. We note that the productivity improvement was tested in one division only. We see no reason why other divisions should not achieve such improvements. We will adopt the staff productivity adjustment for transmission expenses.

c. Review of Specific Accounts

Following is a review of the account-by-account differences between PG&E and staff. We will not provide a discussion of expense accounts where the only differences are the staff's productivity adjustment, deferred maintenance, or escalation rates but will reflect the previously discussed resolution of these issues in the final results.

Account 562
Station Expenses

PG&E requested $7,818,000; the staff recommends $7,440,000, leaving $378,000 at issue.

Both PG&E and staff used a four-year average. The staff recommends deletion of $228,000 which the utility has included to reflect three years of growth in this account. PG&E employed a 4-year average (1977-80) as its base estimate and then applied a 1% per year increase for growth which totals $228,000. PG&E argues that its capacity has been growing at a 2.5% annual rate during the historical period; its plant is aging and thus requires more operating and maintenance expenditures. We conclude that some allowance for growth is reasonable. Accordingly, we will adopt PG&E's estimate.

A second issue dividing PG&E and staff is a shift premium adjustment of $112,000. The staff deleted this item stating that it was included in the utility's labor escalation rate. Staff argues that inclusion of shift premium in the last two years causes a greater upward bias to the trend. Staff's argument has merit. We will adopt the staff recommended adjustment for shift premium.

Account 568 Supervision And Engineering

PG&E requested $1,315,000; the staff recommends $1,290,000, leaving $25,000 at issue.

The primary difference, $16,000, results from the utility using a trend and the staff an average. PG&E argues that its trend shows a 0.1% growth. The staff used an average which does not allow for growth.

We believe the growth reflected by PG&E is reasonable for this account. Accordingly, we will adopt PG&E's estimate.

Account 571.62 Clean Insulators and Bushings

PG&E requested $578,000; the staff recommends $555,000, leaving $23,000 net at issue.

Besides differences due to deferred maintenance and productivity adjustments, the staff used a four-year average and PG&E used a four-year trend to establish their base estimates. This produced a staff estimate higher by $23,000 than PG&E's. Recorded data show an increasing trend for this account. We conclude that the staff estimate is reasonable and should be adopted.

Account 571.63 Replace Line Insulators

PG&E requested $546,000; the staff recommended $488,000, leaving $58,000 at issue.

The primary reason for this difference is the utility's use of a linear trend versus the staff's use of a five-year average. This produces a difference of $42,000. PG&E's trend line shows a 2% annual growth. According to PG&E, this reflects an ongoing program to reduce the number of underinsulated lines that require washing. PG&E argues that in using an average, the staff does not allow for the 2% growth. We will adopt PG&E's estimate since it better reflects growth.

<u>Account 571.68 Conductor Reconditioning</u>

PG&E requested $627,000; the staff recommends $569,000, leaving $58,000 at issue. $38,000 of this difference results from the staff using a trending analysis and PG&E a five-year average.

PG&E argues that staff has computed a negative trend line which results in an estimated 1984 amount which is less than 1982 authorized or recorded. The staff estimate is below the five-year average.

PG&E used a five-year average plus additional amounts for major projects. PG&E argues that the work in this account fluctuates due to major project activity, therefore an average is a better forecast.

Based on recorded data, we conclude that PG&E's estimate is reasonable. Accordingly, we will adopt PG&E's estimate.

<u>Account 571.70 Overhaul and Repair Line Equipment</u>

PG&E requested $27,000; the staff recommends $21,000, leaving $6,000 at issue.

The utility used a linear trend and the staff used an average. PG&E argues that there is a trend line growth rate of 7% and this historical growth rate is not recognized by the use of an average.

We are not satisfied that the staff's average adequately reflects growth in the equipment in service in this account. Accordingly, we will adopt PG&E's estimates.

Account 571.75
<u>Right-of-Way Clearing</u>

PG&E requested $385,000; the staff recommends $360,000, leaving $25,000 at issue.

$16,000 of the difference results from the utility's use of a trend versus the staff's use of a five-year average. PG&E argues that this account has been growing at a 1% annual rate because of restrictive practices imposed on right-of-way clearing programs by various governmental agencies and property owners.

We conclude that staff's average does not provide for the growth cited by PG&E. We will adopt PG&E's estimate.

The following table sets forth the adopted expenditures for Transmission Expenses.

Electric Department

TRANSMISSION EXPENSE

Test Year 1984

(000's Omitted)

Account No.	Description	PGandE	Staff	Adopted
	Operation			
560	Supervisions and Engineering	$ 3,050	$ 3,058	$ 3,050
562	Station Expenses	7,818	7,440	7,706
563	Overhead Line Expenses	629	622	629
564	Underground Line Expenses	68	68	68
565	Transmission of Electricity by Others	744	739	744
566	Miscellaneous Transmission Expenses	840	833	840
567	Rents	201	201	201
561	Load Dispatching	1,910	1,913	1,910
	Total Transmission Operation Exps.	$15,260	$14,874	$15,148
	Maintenance			
568	Supervision and Engineering	$ 1,315	$ 1,290	$ 1,315
569	Structures	155	153	155
570	Station Equipment	4,583	4,488	4,583
571	Clean Insulators and Bushings	578	555	587
571	Replace Line Insulators	546	488	537
571	Stubbing Poles	151	49	50
571	Moving Poles and Guys	57	55	56
571	Pole Treating	118	18	18
571	Emergency Repairs	101	101	101
571	Conductor Reconditioning	627	569	614
571	Temporary Service Set-Up Work	345	339	341
571	Overhaul and Repair Line Equipment	27	21	27
571	Paint Poles, Towers and Accessories	436	220	220
571	Other Overhead Line Maintenance	713	589	596
571	Tree Trimming	1,319	1,319	1,319
571	Vegetation Control	121	118	121
571	Right-of-Way Clearing	385	360	385
572	Underground Lines	220	213	215
573	Miscellaneous Transmission Plant	76	73	74
	Total Transmission Maintenance Exps.	$11,873	$11,018	$11,314
	Total Transmission Expenses (1981 Dollars)	$27,133	$25,892	$26,462
	Escalation Amounts			
	Labor	4,496	4,320	4,392
	Non-Labor	1,426	831	961
	Total (1984 Dollars)	$33,055	$31,043	$31,815

4. Distribution Expenses

In 1981 dollars, PG&E's estimate of total Distribution Expenses of $178,119,000 exceeds the staff's estimate of $169,512,000 by $8,607,000. The factors causing this difference are:

Deferred Maintenance	$1,526,000
Productivity Adjustment	347,000
Estimating Technique	1,518,000
Shift Premium	112,000
Automated Mapping System	578,000
PCB Transformer Replacement Program	4,211,000
Tree Trimming	315,000
Total	$8,607,000

Deferred maintenance and the productivity adjustment are common to many distribution accounts. Therefore, these issues will be discussed prior to the account-by-account review. Likewise the PCB transformer replacement program is discussed separately.

a. Productivity Adjustment

The staff witness' 4% labor productivity adjustment of $347,000 is based on the CMP report discussed previously in Transmission Expenses. We see no reason why these productivity gains cannot be realized in all divisions. Accordingly, we will adopt the staff-recommended adjustment for Distribution Expenses related to crew work. We will not adopt a productivity adjustment to supervision Accounts 580 and 590 since these accounts do not directly relate to crew work.

b. Deferred Maintenance

Based upon Edison's D.82-12-055, staff recommends a disallowance of $1,526,000 for deferred maintenance. For the reasons discussed previously, we adopt the staff adjustment.

c. PCB Transformer Replacement Program

There was considerable public interest in this matter. The hearing room was full to capacity on the day when this issue was examined. Several members of the public participated in cross-examination of the witnesses.

The main issue is whether PG&E can accelerate its proposed 4½-year program to replace all underground PCB transformers. After review of PG&E's schedule, staff agreed that it was reasonable. The testimony of PG&E and IBEW concludes that no faster schedule is feasible without jeopardizing the safety of PG&E employees since changing these transformers involves complicated and risky procedures.

Staff took no exception to PG&E's estimate of the cost of the program. The revenue requirements for 1984 and 1985 are \$4,009,000 and \$5,942,000, respectively. Total cash outlays, that is, for both capital and expense during the 1983 through 1987 period, when this program is to be undertaken and completed, are estimated at \$63,941,000. In addition, there is provision in the 1985 attrition allowance for an additional \$1.9 million needed to expand the PCB underground transformer program.

This program impacts Distribution Expense, Depreciation, Taxes, and Plant and Rate Base accounts.

We will reflect the above revenue requirements in the adopted results of operations.

d. Review of Specific Accounts

We will discuss the accounts where there is a difference between PG&E and staff. We will not discuss accounts where the only differences are due to deferred maintenance, productivity adjustments, the PCB transformer replacement program, or escalation rates but will reflect the previously discussed resolution of these issues in our adopted summary of earnings.

Account 582
Station Equipment

PG&E requested \$11,003,000; the staff recommends \$10,891,000, leaving \$112,000 at issue. The difference is due to a disallowance by the staff of shift premium pay. We will adopt the staff recommendation.

Account 584 Underground
Line Expense

PG&E requested $2,690,000; the staff recommends $2,565,000, leaving $125,000 at issue. The primary difference between utility and staff is estimating technique in the amount of $110,000. Staff made its recommended reduction based on a reduced estimate of customer growth. PG&E derived its estimate using a trending analysis. The coefficient of determination of the resulting trend shows an R-Squared of .94, which indicates a high degree of statistical reliability. We will adopt the PG&E estimate.

Account 586
Meter Expenses

PG&E requested $12,670,000; the staff recommends $12,489,000, leaving at issue $181,000. The primary cause of the difference is estimating technique.

Based on recorded data, we find PG&E's estimate reasonable. We adopt PG&E's estimate.

Account 587.70 Investigating and
Adjusting Service Complaints

PG&E requested $8,288,000; the staff recommends $7,179,000, leaving $1,109,000 at issue. The difference between utility and staff is due to estimating technique.

Based on recorded data, we conclude that PG&E's estimate is reasonable. We adopt PG&E's estimate.

Account 588.60 Distribution
Maps and Records

In 1976, PG&E, under the Commission's direction, began studying the feasibility of automated mapping of all utility facilities. PG&E's pilot automated mapping project in the Peninsula District (MIDAS) is nearing completion, and expansion to the entire San Jose Division is expected to be completed in 1985. The staff agrees that MIDAS will produce benefits in at least 11 separate areas. With the single exception of the assumed savings from this program in the test year, the staff supports the utility's request to expand the project to the entire San Jose Division if the results of a cost-benefit evaluation (to be completed in October 1983) are favorable.

PG&E indicated that savings from automated mapping will exceed the 1977 feasibility study estimates. The savings will eventually occur in three areas: elimination of manual mapping activities where MIDAS is fully operational; short-term deferral of mapping; and increased efficiencies that may eventually result from the use of better information. PG&E estimates that $178,000 of manual mapping expenses can be saved in 1984 through use of MIDAS in the Peninsula District, and through deferral of some manual mapping until MIDAS becomes operational in the San Jose Division. But, PG&E witness Whelan testified, further benefits from increased efficiencies will be marginal in the test period.

We conclude that staff overestimates the savings from MIDAS for the test year. The PG&E estimated savings of $178,000 in 1984 is reflected in its estimate. We will adopt the PG&E estimate for this account.

Account 592
Station Equipment

PG&E requested $3,444,000; the staff recommends $3,391,000, a $53,000 difference. The difference is due to estimating technique.

PG&E witness Nesbit employed a five-year average with a positive adjustment for PCB clean-up costs and a negative adjustment due to a change in breaker maintenance intervals. The average was used as opposed to a trend due to a poor R-Squared.

The staff witness based his labor estimate on length of overhead line. The staff witness stated that his estimate is based on growth, yet his base estimate for 1984 is below both 1981 recorded and 1982 recorded expenditures. We will not adopt the staff recommendation.

Account 593.62 Clean
<u>Insulators and Bushings</u>

PG&E requested $497,000; the staff recommends $443,000, leaving $54,000 at issue. The primary cause of the difference between utility and staff is an estimating technique difference equaling $54,000.

PG&E used the linear trend line to find the embedded growth in this account of 2.5%. This account includes an intensive program to improve reliability. Also, PG&E is increasing its miles of line by 1.2% per year.

The staff witness estimated this account based on miles of line and he asserts that there will be a decline in expenses due to installation of insulators that remain clean for a longer period of time.

Recorded data show an increasing trend in this account. We will adopt PG&E's estimate.

Account 593.73
<u>Tree Trimming</u>

PG&E requested $21,886,000; the staff recommends $21,570,000, leaving $316,000 at issue. Staff made a 1.5% reduction to this account to reflect savings resulting from the use of insulated overhead distribution wire, known as tree wire.

PG&E argues that savings accruing from tree wire are embedded in historical costs. PG&E also argues that the California Division of Forestry has been pressing the utility to perform more tree trimming, and PG&E is trying to comply. PG&E notes that tree trimming is one of the key components of the utility's expanded reliability improvement program.

Based on recorded data, we conclude PG&E's estimate is reasonable. We will adopt PG&E's estimate.

Account 593.74
<u>Vegetation Control</u>

PG&E requested $921,000; the staff recommends $907,000, leaving $14,000 at issue. The difference between PG&E and staff is due to estimating techniques. Staff based its estimates on the miles of line. PG&E used a five-year average and adjusted it for the Compression Connector Program (negative $106,000) and a 2% growth in new lines. According to PG&E this account fluctuates widely due to the amount of precipitation. Therefore, PG&E contends, an average is the most logical base for estimating test year expenses.

Based on recorded data, we find PG&E's estimate reasonable. We will adopt PG&E's estimate.

The adopted Electric Department Distribution Expense is shown in the following table.

Electric Department

DISTRIBUTION EXPENSE

Test Year 1984

(000's Omitted)

Account No.		PG&E	Staff	Adopted
	OPERATION			
580	Supervision and Engineering	$ 20,372	$ 20,343	$20,372
582	Station	11,003	10,891	10,891
583	Overhead Line Expenses	5,100	5,099	5,099
583	Removing and Resetting Line Transformers	7,764	7,700	7,700
584	Underground Line Expenses	2,690	2,565	2,675
585	Street Lighting and Signal Systems Expenses	1,461	1,461	1,461
586	Meter Expenses	12,670	12,489	12,670
587	Investigating and Adjusting Service Complaints	8,288	7,179	8,288
587	Radio and TV Interference Work	572	572	572
587	Other Work on Customer Premises	140	140	140
588	Distribution Maps and Records	6,740	6,162	6,740
588	Miscellaneous Distribution Expenses	18,090	18,089	18,089
589	Rents	251	251	251
	Total Distribution Operation Expenses	$ 95,141	$ 92,941	$94,948
	MAINTENANCE			
590	Supervision and Engineering	$ 10,826	$ 10,765	$10,826
591	Structures	277	277	277
592	Station Equipment	3,444	3,391	3,444
593	Clean Insulators and Bushings	497	443	494
593	Replace Line Insulators	1,542	1,532	1,532
593	Stubbing Poles	500	170	170
593	Moving Poles and Guys	650	645	645
593	Pole Treating	699	162	162
593	Emergency Repairs	1,503	1,502	1,502
593	Conductor Reconditioning	10,467	10,172	10,172
593	Temporary Service Set-up Work	818	815	815
593	Overhaul and Repair Line Equipment	1,380	1,366	1,366
593	Paint Poles, Towers and Accessories	45	19	19
593	Other Overhead Line Maintenance	6,505	6,346	6,346
593	Tree Trimming	21,886	21,570	21,885
593	Vegetation Control	921	907	921
593	Right-of-Way Clearing	402	402	402
594	Underground Lines	9,280	9,095	9,095
595	Line Transformers	4,702	4,636	4,636
593	Overhead Services	2,343	2,280	2,280
594	Underground Services	693	691	691
596	Street Lighting and Signal Systems	1,590	1,588	1,588
597	Meters	780	780	780
598	Miscellaneous Distribution Plant	6	6	6
	Total Distribution Maintenance Expenses	$ 81,756	$ 79,560	$ 80,054
	Total Distribution Expenses (1981 Dollars)	$176,897	$172,501	$175,002
	Escalation Amounts			
	Labor	28,837	28,059	28,460
	Non-Labor	10,388	6,324	7,173
	Total (1984 Dollars)	$216,122	$206,884	$210,635

5. Customer Accounts Expenses

PG&E's electric department customer accounts request totals $77,386,000, the staff's $72,904,000, leaving $4,512,000 in 1981 dollars in dispute. The reasons for the differences between PG&E and staff are the following:

Estimating Technique	$1,244,000
Customer Awareness Program	2,151,000
Manual Meter Reading Subtraction	522,000
Postage Rates	947,000
Uncollectible Accounts	(353,000)
Rounding Differential	1,000
Total	$4,512,000

Two of these differences, estimating technique and Customer Awareness Program, are common to many accounts in the electric and gas departments. For this reason, they will be discussed generically prior to the account-by-account discussion which follows.

a. Estimating Technique

Staff witness S. D. Inn selectively used a combination of 1981 and 1982 recorded data. He considered 1982 expenses to be unusually high and therefore concluded that they could not be used as a basis for estimating test year expenses. Instead, the staff witness based his estimates on PG&E's 1981 recorded costs per customer and the staff's 1984 estimate of customers.

PG&E argues that although the staff witness considered 1982 expenses to be unusually high, he agreed that the relative cost per customer in 1982 was nearly identical to the cost per customer in each of years 1977, 1978, and 1979. PG&E further argues that the staff witness recognized that the utility had incurred additional customer accounts expenses in 1982 when it transferred some A&G expenses to customer accounts, expanded its energy theft program, and added meter reader supervisors. However, PG&E points out that the staff witness did not make any adjustments to reflect these additional expenses in 1982.

PG&E notes that its estimate is based on 1982 recorded data, with costs for the estimated year developed from forecasts of expense by the major departments within PG&E who charge their expenses to customer accounts. According to PG&E, it reflects the new programs PG&E has instituted as a result of the 1982 rate case decision.

We note that staff did not completely reject 1982 recorded data. Rather, it used 1982 data selectively in combination with 1981 recorded data. Our concern is that staff, by selectively ignoring the latest recorded information "because it was too high", may not have adequately reflected growth and worthwhile new programs. We will review this aspect on an account-by-account basis.

b. Customer Awareness Programs

Staff recommended a disallowance for the Customer Awareness Program of $2,151,000 for the electric department, and $1,287,000 for the gas department. According to PG&E, customer awareness programs are communications activities designed to inform customers of utility matters which directly concern them such as rate changes, billing procedures, and how to read meters.

The staff witness agreed that by informing its customers of impending rate increases, PG&E can decrease the number of phone calls and expenses related to the customer contacts that would otherwise occur. The staff witness also stated that if the utility had known that the Customer Awareness Program was not going to be funded by the Commission, PG&E likely would have increased its expense estimates that relate to customer contacts.

The staff witness agreed that the Customer Awareness Program also includes dollars for safety issues, lifeline rate changes, and third-party notification. He also agreed that the following costs should be recovered even though he had not included them in his estimates:

1. Safety communications--$60,000 (electric department--$38,000; gas department--$22,000).

2. Lifeline or baseline rate change notification--$14,000 (electric department--$8,000; gas department $6,000).

3. Third-party notification procedures specified by OII 49--$20,000 (electric department--$11,000; gas department--$9,000).

4. Pay Station Notification--$12,000 (electric department--$7,000; gas department--$5,000.)

We will authorize these amounts. The utility's requested customer awareness expenses and the adopted expenditures are:

	Total for Electric And Gas Department	
	PG&E	Adopted
1. High Bill	$2,000,000	$500,000
2. Read Your Own Meter	500,000	50,000
3. Community Meetings	40,000	0
4. Plan Your PG&E Bill	500,000	100,000
5. Balanced Payment Plan	300,000	150,000

The staff witness contends that the first three programs should not be allowed because they allegedly violate the advertising provisions in D.84902.

When the staff witness was asked to distinguish the fourth and fifth programs (which he would have allowed had they met his test of cost-effectiveness) from the first three, he explained that they fit within the "more efficient service to ratepayers" and "encouragement of more efficient use of utility service" standards of D.84902.

PG&E argues that the two standards quoted by the staff witness are equally applicable to the first three programs. Also, PG&E asks, how is a customer going to plan his bill if he does not know how to read his meter?

We will review the above five programs individually.

<u>High Bill</u>

Staff argues that the Commission has specifically stated in previous decisions that advertising "justifying present rate levels, the requirement for higher rates, and the need for plant expansion, also appear to fall outside the boundaries of our guidelines." (78 PUC 693, 694, D.84902.) Staff contends that PG&E has attempted to justify the High Bill Notification Program on the basis of a letter from the Commission's Executive Director asking that such notification be given with respect to an anticipated increase in gas rates, and a conversation between PG&E's executives and a former Commissioner. (Exhibit 107.)

The staff submits that Exhibit 107 does not reverse the Commission policy as stated in D.84902. According to staff the letter from the Executive Director is a specific request to advise customers of increases resulting from the Natural Gas Policy Act of 1978. It specifically excludes increases relating to general rate cases.

Staff notes that the utility also cited two newspaper articles discussing the uproar that accompanied the increase in PG&E's rates following the last general rate case and the fact that the Commission and utility had not prepared customers for the size of the rate increases. The staff submits that there is nothing essentially wrong with the discomfort experienced by the Commission and the utility being proportional to the discomfort experienced by ratepayers when a rate increase is granted.

The concern we have is the impending switch from lifeline to baseline rates which is discussed later in this opinion. Knowing that this change could severely impact some customers, it would be shortsighted for the Commission not to provide for customer notification. Therefore, PG&E should be provided with funding for this purpose.

We conclude that if funds are not spent on a program explaining the lifeline to baseline shift PG&E will incur additional expense to handle customer inquiries and complaints. Advance notification will result in reduction of operating costs and more efficient service to the ratepayer.

We will allow $500,000 for this program.

d. Read Your Own Meter

According to staff, the "Read Your Own Meter" program represents expenses for advertising only. The utility already has brochures and information regarding how to read your own meter, and this is available from the utility upon request from a customer. The program at issue here relates to additional advertising to try and make customers aware of the program. The staff witness stated that he did not believe that informing customers on how to read their own meters met any of the specific criteria for which public relations expense was allowed in D.84902.

Since the brochures are already available it would be wasteful not to distribute them. PG&E requests $500,000 to do this. We are convinced there is a less expensive way to let customers know that such material is available. For example, an insert in the customer bill could be used to inform customers of this material at small extra cost.

PG&E's request is reduced to $50,000.

e. Community Meetings

The staff witness indicated that the "Community Meetings" program failed the test set forth in D.84902. It should be noted that the "Community Meetings" program would institute a series of meetings between members of the public and PG&E representatives which according to staff would provide virtually the same services as the public witness hearings which the Commission requires before rate applications are processed. In this fashion the utility would have the opportunity to discuss particular bill complaints with customers and provide them with PG&E informational and promotional literature. To the extent that these meetings are in large part duplicative of public witness hearings which are occuring throughout the year and are advertised at ratepayer expense, the staff submits that an additional $40,000 program is not necessary.

We will adopt the staff recommendation, and not authorize this expenditure.

f. Plan Your PG&E Bill

The "Plan Your Own PG&E Bill Kit" was found by the staff witness to possibly fall within the scope of the criteria listed in D.84902 in that it could encourage more efficient use of the utility's services, but the staff witness disallowed the expense on the ground that the utility had not demonstrated to his satisfaction that the same information could not be provided in a more cost-effective manner.

According to staff the "Plan Your PG&E Bill Kit" is a large, professionally designed and assembled packet of information regarding common energy use around the home and provides a chart on which to calculate that use for any particular home. It contains sophisticated graphics and is printed in several colors on heavy-grade paper. There has been no showing in the record as to the reasonableness of the printing expense incurred in this particular portion of the Customer Awareness Program.

We note staff's concerns. We believe that the same information can be provided in a more cost-effective manner. We see no need for the material to be "printed in several colors on very heavy grade paper". Accordingly, we will allow $100,000.

g. Balanced Payment Plan

These expenses are related to advertising to advise customers of the existence of the "Balanced Payment Plan". According to staff there has been no demonstration in the record that the advertising expenses proposed for this program are reasonable, and no explanation of why the utility's existing customer service network cannot provide this information in response to customer requests.

We conclude that this program serves the need of many customers.

PG&E requests $300,000. Here again, we are convinced there is a less expensive way to get the message to the customer. We will reduce PG&E's request by half and allow $150,000 for this program.

Review of Specific Accounts

We will now address the account-by-account differences between PG&E and staff in the customer accounts area.

Account 901
Supervision

PG&E has requested $4,081,000; the staff recommends $4,038,000, leaving $43,000 at issue. This difference is caused by the use of different estimating techniques. Based on recorded data, we will adopt PG&E's estimate.

Account 902 Meter
Reading Expenses

PG&E has requested $12,716,000; the staff recommends $11,734,000, leaving $982,000 at issue.

The primary difference is the staff's disallowance of $522,000 for the manual meter reading subtraction process. The staff witness contends that the manual subtraction exercise constitutes a duplication of effort and, therefore, if PG&E had done something earlier to improve its meter reading system, this duplication of effort would no longer exist.

PG&E's witness testified that it is necessary under PG&E's meter reading system for meter readers to do subtraction, because it alerts the meter reader to double check the reading if the reading is substantially different from previous usage. According to PG&E, this check for potential meter reading errors holds down possible rereads which are very costly to the utility, and annoying to the customer.

Staff argues that PG&E is the only California utility which requires these types of manual meter reading calculations and the only one that has not taken advantage of new meter reading technology. According to staff the basic technology which has replaced manual meter reading is the Optical Character Reading system or OCR, which requires the meter readers to make marks on a card or piece of paper which can be read by an optical scanner, thus automatically transferring the information to an electronic data processing system. Staff notes that PG&E's witness conceded that OCR technology has been available to the utility since at least 1973-1974.

Staff notes the following excerpt from the CMP report:

> "Customer services has long recognized that the current meter reading system is archaic, but has moved slowly in installing newer technology because of a desire to minimize long-term costs regardless of near-term consequences."

PG&E submits it would not be on the brink of implementing an electronic meter reading system if it had recently installed an OCR system. According to PG&E the electronic meter reading system is the only system available that truly revolutionizes the meter reading and billing process.

We expect PG&E to implement the electronic meter reading system as soon as it is perfected. Also, we see no reason why the ratepayer should continue to pay for manual subtraction. We expect PG&E to phase out manual subtraction by the time of its next general rate case proceeding. Accordingly, we will adopt half the staff-recommended adjustment for manual subtraction.

We will expect a full report from PG&E on the electronic meter reading system and its implementation. We are concerned about the costs of meter reading and will not hesitate to penalize PG&E if no improvements are made by the time of PG&E's next general rate case.

proceeding. PG&E anticipates it will be able to demonstrate significant meter reading savings in the next general rate case. We will expect PG&E to demonstrate quantifiable savings in its next general rate case showing.

A second issue dividing PG&E and staff involves customer awareness expenses. There is a $290,000 difference between the parties related to the Reading Your Own Meter program. The amount allowed was set forth previously.

The final difference between the utility and staff involves estimating technique. $170,000 is at issue. We will not adopt the staff adjustment.

Account 903 Customer
Contracts and Orders

PG&E has requested $17,760,000; the staff recommends $15,944,000, leaving a difference of $1,816,000.

The primary cause of the difference for the test year is staff's disallowance of Customer Awareness Program expenses, amounting to $1,665,000. This amount is comprised of the following programs: High Bills--$1,281,000; Plan Your PG&E Bill--$320,000; Safety Communications--$38,000; and Community Meetings--$26,000. The amounts allowed were set forth previously.

The remaining issue, which involves a difference of $151,000, is due to the use of different estimating techniques. We will adopt the staff adjustment.

Account 903 Customer
Billing and Accounting

PG&E has requested $9,447,000; the staff recommends $9,117,000, leaving a difference of $330,000. Two issues cause this difference. The staff's disallowance of Customer Awareness Program expenses accounts for $178,000 ($170,000--Balanced Payment Plan, $8,000--Lifeline Changes). The amounts allowed were set forth previously. The remainder, $152,000, is due to the use of different estimating techniques. We will not adopt the staff recommended adjustment for estimating technique.

Account 903 Mailing
Customers' Bills

PG&E has requested $6,0709,000; the staff recommends $5,220,000, leaving a difference of $850,000. $849,000 of this difference occurs because PG&E's witness assumed postage rates to be 23¢ for first-class mail in 1984. (Exhibit 45, pp. 11, 24.) The staff, in contrast, assumed no increase in postage costs (Exhibit 158, p. 7-7; Exhibit 159, p. 9-7). The remaining $1,000 difference is due to rounding.

PG&E developed its postage rate estimate using a regression analysis of postage rate increases against changes in CPI. The staff maintains its traditional position with regard to postage expense and recommends that no increase in postage be included in test year expenses unless an increase is definite. Also, if a postage increase is enacted during the test year, staff recommends that postage expenses be adjusted to reflect the increase in the attrition adjustment.

We will adopt staff's recommendation. If there is a known increase in postage rates in 1984 this will be reflected in the 1985 attrition allowance.

Account 903
Collecting Expenses

PG&E has requested $15,598,000; the staff recommends $15,138,000, leaving a difference of $460,000. The primary dispute involves the use of different estimating techniques, amounting to $344,000.

There are several reasons for the increase in expenditure levels for this account. We will not adopt the staff adjustment for this item.

A second issue is the Customer Awareness Program, which involves an $18,000 difference. $7,000 is for the Pay Station Program and $11,000 is for third-party notification requirements. We will adopt PG&E's estimate.

The final difference of $98,000 occurs because the staff used existing postage rates for 1984. If there is an increase, we will reflect this increase in the 1985 attrition calculation.

Account 904
Uncollectible Accounts

PG&E has requested $5,408,000 for Uncollectible Accounts based on a .251% uncollectible factor; the staff recommends $5,839,000, also based on a .251% uncollectible factor, leaving a difference of $431,000. The difference for uncollectibles is related to the staff's higher revenue estimate.

To calculate the uncollectible expense for the test year related to base rates, we will use a .251% uncollectible factor in conjunction with the adopted revenue estimate.

Account 905 Miscellaneous
Customer Accounts Expenses

PG&E has requested $5,986,000; the staff recommends $5,602,000, leaving a difference of $384,000. The cause of this variance is the use of different estimating techniques.

Recorded 1981 and 1982 expense levels are $5,280,000 and $5,989,000 respectively. PG&E used recorded 1982 with some adjustments. Staff used 1981 data. While this account reflects customer growth, we believe the growth in expenses between 1981 and 1982 is excessive. We will adopt staff's estimate.

Account 905
Rents

PG&E stipulated to the staff's estimate of $320,000. We will adopt the staff estimate.

Electric Department

CUSTOMER ACCOUNTS EXPENSES

Test Year 1984

(000's Omitted)

Account No.	Description	PGandE	Staff	Adopted
901	Supervision	$ 4,081	$ 4,038	$ 4,081
902	Meter Reading Expenses	12,716	11,734	12,194
903	Customer Contracts and Orders	17,760	15,944	16,517
903	Customer Billing and Accounting	9,447	9,117	9,210
903	Mailing Customer Bills	6,070	5,220	5,220
903	Collecting Expenses	15,598	15,138	15,500
905	Miscellaneous Customer Accounts Exps.	5,986	5,603	5,602
905	Rents	320	320	320
	Total Excluding Uncollectible Accounts	$71,978	$67,113	$68,644
904	Uncollectible Accounts	5,438	5,791	5,583
	Total Including Uncollectible Accounts (1981 Dollars)	$77,416	$72,904	$74,227
	Escalation Amounts			
	Labor	13,080	12,742	12,912
	Non-Labor	2,366	1,209	1,449
	Total (1984 Dollars)	$92,862	$86,855	$88,588

6. Customer Service and Information Expense

The following tables set forth the adopted conservation and load management expenses for the test year. The specific programs are discussed later in this opinion.

Pacific Gas and Electric Company
Electric Department
CUSTOMER SERVICES AND INFORMATION EXPENSES
(Excluding Load Management)
Test Year 1984
(000's Omitted)

Account No.	Description	PG&E	Staff	Adopted
907	Supervision	$7,698	$6,873	$ 6,833
908	Customer Assistance Expense	46,265	36,398	22,226
909	Informational and Instructional Advertising Expenses	6,549	3,548	3,548
910	Miscellaneous Customer Service & Information Expenses	7,748	6,705	6,630
	Total Cust. Services and Information Exp. (1981 dollars)	$68,260	$53,524	$39,237
	Escalation Amounts			
	Labor	3,394	3,277	3,374
	Non-Labor	8,953	4,124	2,947
	Total (1984 dollars)	$80,607	$60,925	$45,558

Electric Department
CUSTOMER SERVICE AND INFORMATION EXPENSES
BY PROGRAM
(EXCLUDING LOAD MANAGEMENT)

Test Year 1984

(000's Omitted)

Program	PGandE	Staff	Adopted
Conservation			
Builder Conservation	$ 2,181	$ 1,863	$ 1,363
Appliance Efficiency	7,309	8,689	5,119
Master Meter Conversion	1,408	1,408	375
Energy Management	11,320	9,822	7,889
Agricultural Energy Management	1,694	1,694	1,411
Energy Management Incentives	33,223	20,775	14,478
Technical Support & Demonstration	1,889	1,889	1,449
Communications & Seminars	3,811	1,205	1,205
General Customer Inquiries	949	1,111	880
Program Evaluation	1,305	1,897	1,897
Total Conservation	$65,089	$50,353	$36,066
Marketing Services	3,171	3,171	3,171
Total (1981 Dollars)	$68,260	$53,524	$39,237

Electric Department

LOAD MANAGEMENT OPERATING EXPENSES

Test Year 1984

(000's Omitted)

Account No.	Description	PGandE	Staff	Adopted
907	Supervision	$ 2,313	$ 834	$ 1,684
908	Customer Assistance Expense	17,802	6,419	13,132
909	Informational and Instructional Advertising Expenses	821	296	842
910	Miscellaneous Customer Service & Information Expenses	1,748	630	1,179
910	Rents	0	0	0
	Total Load Management Operating Expenses (1981 dollars)	$22,684	$8,179	$16,837
	Escalation Amounts			
	Labor	2,560	883	1,850
	Non-Labor	2,063	479	1,086
	Total (1984 dollars)	$27,307	$9,541	$19,773

7. Administrative and General Expense (A&G)

PG&E's estimate of total electric department A&G expenses of $351,651,000 exceeds the staff's estimate of $288,715,000 by $62,936,000. With the exception of Property Insurance and Premiums (Account 924) and Pensions and Benefits (Account 926), which are in 1984 dollars, all differences are in 1981 dollars. The differences between PG&E and staff are the following:

Effort Study	$13,219,000
Estimating Methodology (Accounts 920, 921, 922)	16,510,000
Property Insurance and Premiums (Account 924)	814,000
RD&D (Account 930.2)	8,973,000
Feasibility Studies (Account 930.2)	6,845,000
EEI (Account 930.2)	7,103,000
Industry Association Dues (Account 930.2)	381,000
Three Mile Island Cleanup Costs (Account 930.2)	639,000
EEO Litigation Expenses (Account 930.2)	125,000
Rents (Account 931)	499,000
Facilities Development Estimate (Account 923)	-168,000
Pension and Benefits (Account 926)	14,197,000
Franchises	-199,000
Total	$62,936,000

a. CMP Audit

PG&E's A&G witness, D. H. Hegler, lists implementation of the CMP Audit recommendations as one of the causes of PG&E's increase in A&G expense. The expansion of the Internal Auditing Department is one of the major items. Hegler notes that costs related to implementing the audit recommendations show up in A&G expense categories while the benefits show up in other functional areas. According to PG&E, these CMP-related expenses are a direct result of the Commission's requirement that PG&E perform a management audit and then implement the results.

PG&E notes that the CMP audit and final action plans were approved by this Commission. The Commission has carefully monitored PG&E's progress in implementing the CMP recommendations as the utility is required to submit periodic progress reports in OII 80 on the implementation of all CMP recommendations. PG&E argues that despite the Commission's intense interest in the CMP audit, the staff recommends not only that PG&E's request for additional staff in internal auditing be disallowed, but that the funding level be cut back to a 1981 expenditure level.

PG&E further argues that another example of disregard for CMP recommendations can be found in the staff witness' recommended treatment of the Computer Systems and Services Department. While agreeing that the cost is related to the CMP report, the staff witness excludes the cost from his estimates. Therefore, PG&E submits it is getting contradictory signals from the staff on implementing the CMP recommendations.

The staff witness, R. Joshi, argues that a major defect of the utility's presentation is the complete omission of any benefits or specific costs of implementing the CMP audit recommendations. Staff notes that in Exhibit 8 at page 4A-3 and continuing, PG&E lists at least eight separate recommendations of the CMP audit which would be implemented in the test year but claims that the associated savings may not appear until several years following implementation of the program. Staff argues that an analysis of these particular recommendations would seem to contradict that assertion. For instance, staff notes, a number of the recommendations involve the creation of new vice president positions and the addition of various personnel such as an assistant to the president and productivity engineer. Once these people are on the job performing their new duties, staff wonders why the savings will not begin to accrue immediately.

Turning to savings in the computer area, staff argues that the PG&E witness' own testimony contradicts the notion that the savings will appear only in the future. Staff notes that with respect to the second computer center which CMP recommended in PG&E's proposal, the witness states, "Eventually we envision some productivity gains here, certainly not long after the computer is in being." However, staff points out that no savings associated with these productivity gains are included in any of the utility's estimates.

We are not prepared to reflect additional productivity savings related to the A&G area in the test year because many of the CMP recommendations are in the course of implementation or still have to be implemented. There is no evidence to quantify savings beyond those already included by PG&E. If we made productivity adjustments and such savings are not realized in the test year, we would in effect be penalizing PG&E. Therefore, in the next general rate case proceeding, we expect an exhibit prepared by PG&E reflecting: (1) CMP recommendations implemented; (2) cost of implementing recommendations; and (3) savings realized. We expect such additional productivity to be accounted for in the next proceeding. PG&E should provide an expert witness who will address the question of measuring productivity gains in the A&G area and steps taken by PG&E to arrest rapidly escalating A&G expenses.

Staff further argues that another example of the utility's neglect of real savings in expense is found in the fact that the utility has not included additional savings for the installation of word processors and small computers it has estimated will be added in the test year. Staff notes that according to PG&E's witness these units have a cost benefit ratio of between 3.5 to 1 to 6.5 to 1. Accordingly, staff argues these rates would indicate that the addition of every small computer or word processor should result in a significant net reduction in utility expense. Again, there is no evidence upon which to quantify the savings beyond those already included by PG&E.

In summary, we share staff's concerns regarding the rapid escalation of expenses in the A&G area. We grant a sizeable increase in the A&G area because we agree that the CMP recommendations should be implemented. However, in PG&E's next general rate case proceeding, we expect to see productivity gains reflected. We expect PG&E to carefully study the question of productivity in the A&G area and in particular, advise the Commission on the steps taken to arrest the rapid increase in these expenses. We recommend that PG&E create an in-house task force to review and correct the situation.

b. Effort Study

In determining the appropriate level of expenses in 1984 to be transferred from Accounts 920, A&G Salaries, and 921, Supplies and Expenses, and charged to construction via Account 922, PG&E surveyed the construction activity levels of all general office departments. (Exhibit 8, p. 11A-10.) This survey, called an effort study, is new and replaces the old methodology the utility used in prior rate cases.

PG&E notes that the use of an effort study is in complete conformance with the FERC Uniform System of Accounts. Furthermore, PG&E notes, effort studies are the norm. Staff agreed that both Edison and SDG&E use an effort study when seeking rate relief from this Commission.

The issue centers around the staff witness' position that "not enough effort has been put into the effort studies." The difference between PG&E and staff amounts to a $13.2 million test year revenue requirement. However, it should be remembered that the difference only relates to the amount capitalized in the test year. The ratepayer pays these dollars sooner or later, depending on the percentage of costs capitalized.

Staff notes that the major change in construction allocation is in the Planning and Research Department. This change is due to an organizational change and partly due to the new policy of expensing rather than capitalizing RD&D expenditures. Also, staff notes that the Facilities Planning Section now does more work acquiring electric energy from facilities owned by others rather than planning construction of its own power plants.

We keep in mind that the answer does not lie in prior recorded percentages. The reason is that recorded percentages reflect the percentage previously chosen for the period based on a prior effort study or some other rationale.

PG&E notes that in 1982, it conducted a study to determine the percentage which should be used for the test year to reflect construction as a percentage of total ~~activity for~~ allocating A&G expense. According to PG&E, the study established 17.2% as the appropriate composite figure. We note 33-35% was used in the recent past.

We find that the record substantiates a reduction from the percentage used in the past, but the 17.2% chosen by PG&E appears low compared to the percentage used by other comparable California utilities. On the other hand the staff recommended 29% does not appear to adequately reflect PG&E's shift from major construction projects. Accordingly, for test year 1984, we will adopt 25% as reasonable.

c. Estimating Methodology

In estimating expenses for Accounts 920, 921, and 923, PG&E used a budget approach. (Exhibit 8, p. 11A-9.) Staff based its estimates on 1980 through 1982 recorded data.

Staff agrees that the budget approach is appropriate for these accounts. However, staff disagrees with the alleged practice by PG&E of directly transferring its budget estimates to the test year rate application without making appropriate adjustments. Staff argues that this has the effect of creating a "wish list."

Also, staff argues that PG&E's productivity ratios are poor compared to other California utilities. There was much debate on this issue; however, the evidence is inconclusive. We suggest that staff assign a task force to compare A&G productivity ratios of the four major California utilities. Because of accounting differences between the utilities, we are not prepared to accept ratios simply based on raw numbers without a clear understanding of the makeup of such numbers. The numbers being compared must be comparable.

Turning to the significant increase in A&G expense since 1981, the staff at page 198 of its opening brief argues that:

> "As demonstrated by the PG&E witnesses' own testimony, PG&E has significantly under-estimated its A&G expense in both 1981 and 1982. In 1981, PG&E's requests for A&G expense were $6.7 million and $2.1 million short of what was actually expended in the electric and gas departments, respectively. Likewise, in 1982, the utility requested $4.3 million and approximately $2 million less than they actually expended in the electric and gas departments, respectively. (RT. p. 2502.) The position of the Commission staff is that this represents inefficient and poorly controlled growth in administrative and general expenses, particularly with respect to the general office. It is illuminating in this regard to note that of all the programs discussed in PG&E's Exhibit 4 on cost control and productivity, only a very few relate to general office or A&G expense, and these are mere continuations of present programs. (Exh. 4, p. 28.) In comparison, the utility spends several pages explaining all the various cost control activities which will be implemented in the operating department and customer services. (Exh. 4, pp. 25 through 27.)"

We share staff's concerns regarding PG&E's rapidly escalating A&G expense. However, staff has not substantiated its position that the increase represents inefficient and poorly controlled growth in A&G expenses. On the other hand, while we note that PG&E overspent A&G by $8.8 million in 1981 and $6.3 million in 1982, we are not satisfied with PG&E's showing on A&G productivity.

Regarding PG&E's request in this proceeding, we conclude that PG&E will have to implement the proposed CMP changes for 1984 on a less ambitious scale. We will consider the requested increases on an account-by-account basis.

d. Review of Specific Accounts

Account 920 A&G Salaries

PG&E requested $84,514,000 and staff recommends $75,871,000, for a difference of $8,643,000. The staff estimate is based on a combination of 1981 and 1982 recorded data, and 1983 and 1984 estimated data for the various subaccounts. The estimates are based on the staff witness' judgment that the recorded expense for one of the prior years mentioned is appropriate for the test year without further adjustment.

We will discuss some of the specific differences between PG&E and the staff in various departmental areas. The A&G differences discussed below are on a total utility basis; they do not differentiate between the electric and gas departments. Furthermore, the differences being reviewed only relate to the labor component. Following are eight examples of the differing approaches employed by the staff and PG&E:

(1) PG&E requested $537,000 for the Department of Financial Planning and Analysis. Staff recommends $478,000. According to PG&E the utility is increasing its efforts to raise capital from nontraditional sources (e.g., London Stock Exchange) and additional staffing is required for this effort.

(2) PG&E requested $500,000 for Project Management Development; the staff witness recommends $125,000. The staff witness recommends funding at the estimated 1982 expenditure level. PG&E points out that 1982 was the first year the department was in place. According to PG&E, the department was not fully staffed to accomplish all the goals recommended by the CMP audit.

(3) The staff witness reduced the Governmental Relations Department estimate by $229,000, with $175,000 related to Account 920. The staff witness asserted that this department does not provide substantial benefit to the ratepayer.

PG&E argues that in fact, the Governmental Relations Department provides direct and important benefits to PG&E's customers. For example, it provides liaison between the utility and its state and federal regulatory bodies, and reviews legislation to determine the possible impact on PG&E and its ratepayers. PG&E contends that both these examples have obvious direct benefits for PG&E's customers since regulation and legislation directly affect the costs and types of services being provided by PG&E. Furthermore, when in the past the Commission reviewed expenditures in this Department, PG&E notes that the Commission disallowed 25% of the salaries; 75% of the salary costs were found to have benefit to PG&E's customers.

(4) PG&E requested $380,000 for a Communications Planning Department; the staff witness recommended zero funding. The staff witness eliminated funding for the Communications Planning Department (originally Special Projects Department) because he believed its purpose was to enhance PG&E's public image.

PG&E argues that the establishment of the Communications Planning Department was a direct result of the CMP Audit, and the staff did not express disagreement with the CMP recommendation. PG&E contends that the tasks undertaken by this department range from attitudinal surveys relating to public perceptions of conservation programs and activities, to survey work to improve service to PG&E's customers.

(5) PG&E requested $4,315,000 for the Building and Administrative Services Department; the staff witness recommends $3,855,000, leaving $460,000 at issue. PG&E notes that the staff witness agreed that this department is a service-oriented department and that he would expect that as other departments increase in size, the requirements of this department would increase. PG&E argues that recognizing this relationship, the staff witness should have adopted a 1984 level of expenditures which reflects the growth he projected for a few selected departments.

(6) PG&E requested $15,309,000 for Computer Systems and Services, while the staff recommended $12,961,000. PG&E points out that the main reason for increases in this department was the adoption of CMP recommendations. These expenses relate to the San Francisco computer center and a second computer center recently constructed in Fairfield. PG&E notes that staff disallowed expenditures related to the second computer center even though the center was an outgrowth of CMP recommendations.

We agree that some increase for computer centers is reasonable. While we agree there is a need to improve PG&E computer capabilities, we conclude that PG&E's plans are too ambitious. PG&E should get by with less.

(7) PG&E requested $2,552,000 for Internal Auditing; the staff recommends $940,000. The staff recommended funding level allows the same level of expenditures as recorded in 1981. PG&E notes it is expanding Internal Auditing in direct response to CMP recommendations. We find PG&E's program too ambitious. PG&E should get by with less.

(8) PG&E requested $12,113,000 for its Personnel Department; the staff witness recommends $9,022,000, for a difference of $3,091,000. The staff witness disallowed expenses for engineering trainees; however, he later agreed that funding for some engineering trainees should be allowed, but not at the level requested.

A second issue concerns PG&E's contention that the utility will be experiencing tremendous personnel turnover due to the age of its workforce. According to PG&E, a large number of management personnel were hired in the immediate post-World-War-II period and are now approaching retirement age. PG&E contends it will need to step up its training and hiring efforts to meet the expected turnover.

In addition, PG&E's witness testified that the utility is committed to improving its Affirmative Action Program, a program the Commission has supported. According to PG&E a study by a personnel consultant showed that the ratio of personnel employees to total employees was very low, and that the utility needed to staff-up its Personnel Department.

We generally agree with the objectives of PG&E's Personnel Department Program. However, the program is too ambitious and costly to the ratepayer. PG&E should manage with less.

In summary, we find that the appropriate approach to setting the test year level of expenditure for this account is to provide for a reasonable increase based on recorded expenditures. PG&E requests $84,514,000 or a 6.5% increase per year. The staff recommends $75,871,000 or a 2.7% increase per year based on 1981 recorded expenditures of $69,979,000. We conclude that a 3% increase per year over 1981 recorded levels is reasonable for test year 1984. Accordingly, the adopted expense level for Account 920 is $76,468,000. All the above amounts are in 1981 dollars.

Account 921 Office
<u>Supplies and Expenses</u>

PG&E requested $45,013,000 and staff recommends $33,711,000, leaving a difference of $11,302,000. Recorded expenditures for 1981 are $27,345,000.

According to PG&E, the major reasons for the growth in this account for 1984 include, among others, the following five factors:

(1) A second computer center will be established prior to 1984 and those costs are reflected in Account 921, including the maintenance of the center, the purchase of software for the new computers, and the leasing costs associated with the computers.

(2) The Personnel Department will "be increasing to have affirmative action trainees on the level of about 40 as well as the management progression trainees or management progression personnel of about 50." While these labor costs are charged to Account 920, there are associated expense costs that go into Account 921.

(3) For the first time, there will be costs for state-mandated PCB, hearing loss, and asbestos medical tests.

(4) Account 921 was increased by $3 million for the maintenance of the general office building, specifically waterproofing and caulking of windows.

(5) The Personnel Department budget also includes funds necessary for establishing a new training center since the Emeryville training center is going to be dismantled and PG&E is going to centralize the training facilities in one location by 1984.

Other items in dispute include:

(1) The staff witness' reduction of PG&E's request for Safety, Health, and Claims in Account 921 of $897,000.

(2) PG&E's request for Building Department maintenance was reduced by a total of $2,928,000. The Building Department estimate includes (1) $500,000 to reseal the windows at 245 Market Street, and (2) $150,000 to relamp the General Office complex.

(3) The biggest difference in Account 921 is in the Computer System and Services Department. For this department, PG&E is requesting $18,354,000 in Account 921, while the staff is proposing $11,457,000, a difference of $6,897,000.

PG&E argues that the Computer System and Services Department is primarily growing for two reasons. The first reason is the second computer center in Fairfield. According to PG&E, the staff witness has completely ignored the need for increased computer capacity. He nonetheless agreed that the center is responsive to a CMP recommendation, and that it will provide disaster relief in the event of an emergency at the computer center in San Francisco.

According to PG&E, the computer capability at the San Francisco center has not kept pace with the utility's needs, and the second major reason for cost increases in this department is that Computer Systems and Services has taken over responsibility for budgeting all computer-related technology.

We agree with PG&E that there is a need to improve its computer capability. However, as we indicated in our discussion on Account 920, we believe PG&E should manage with less.

In summary, we find that the appropriate approach to setting the test year level of expenditure for this account is to provide for a reasonable increase based on recorded expenditures. PG&E requests $45,013,000 or a 17.3% increase per year over 1981 recorded levels. Staff recommends $33,711,000 or a 6.5% increase per year. Recorded 1981 expenditures are $27,945,000. We conclude that an 8% increase per year over 1981 expenditures is appropriate for the test year. Accordingly the adopted expense level for Account 921 is $35,202,700. All the above amounts are in 1981 dollars.

We authorize this unusual increase largely because of the need to improve PG&E's computer capability. This amount of increase is not to be construed as an indication of the appropriate level for future increases in this account. As we stated previously, in the next rate case we expect productivity savings to be reflected in PG&E's operations.

Account 922 A&G Expenses
Transferred-Credit

PG&E has requested a credit of $22,279,000, and the staff recommends a credit of $32,063,000, leaving $9,784,000 at issue. The difference is two-fold. First, it reflects PG&E's use of the 17.2% allocation factor to construction based on PG&E's Effort Study, while staff used the 29.3% factor based on the prior method used by PG&E to allocte costs to construction. (See Effort Study discussion, above.) Second, it reflects the different budget recommendations for Accounts 920 and 921. The adopted expense credit will reflect the adopted expenditures for Account 920 and 921 and a 25% allocation factor as discussed previously.

Account 923 Outside
Services Employed

PG&E has requested $6,275,000; the staff recommends $6,443,000. The staff's estimate exceeds PG&E's by $168,000. PG&E stipulates to the staff's estimate.

The reason that PG&E was lower in Account 923 than the staff is that PG&E made revisions to Accounts 920, 921, 922, and 923 after the original application was filed. These revisions are shown in Exhibit 26. The staff accepted these revisions, but when preparing its own estimate included the changes for Accounts 920, 921, and 923, all in Account 920, rather than making the individual account changes. Since the staff reduced its estimate of Account 920 by the same $168,000 in question, this method of estimating Account 923 is reasonable. We will adopt the staff estimate.

Account 924
Property Insurance

PG&E requested $5,352,000; the staff recommended $4,538,000, leaving $814,000 at issue. These figures are in 1984 dollars.

There are two reasons for the staff estimate being $814,000 lower: reduced deductible amounts and increased coverage. The staff witness decided that PG&E's estimate for 1984 should be reduced to a level that is 83% of its request because recorded 1982 property insurance expense was 83% of the utility's estimated 1982 expenses. PG&E's witness stated that expenses for the test year will be one million dollars higher than he originally estimated due to the impact on claims, and consequently on premiums, of two consecutive severe winters. Furthermore, PG&E notes, contrary to the staff witness' impression, PG&E is increasing its deductible amounts in order to hold premiums down, and even with this increase in deductibles, costs will rise faster than originally anticipated. We will adopt PG&E's estimate.

Account 925
Injuries and Damages

PG&E and staff have agreed on an estimate of $17,944,000 for this account. We will reflect this amount in the adopted results.

Account 926 Employee
Pensions and Benefits

PG&E requests $138,431,000; the staff recommends $123,120,000, leaving $15,311,000 at issue. These figures are in 1984 dollars.

As shown in Exhibit 173, both staff witness M F. Crommie and PG&E witness R. H. Cunningham agree on the base estimate of pension and benefit costs. The difference in the final estimates arises from staff and utility using different employee growth factors (staff 5.6% and PG&E 18.48%) over a three-year period and differing escalation estimates. The adopted test year estimate, which is based on Exhibit 173, reflects the employee growth factor embedded in the adopted expense estimates and the adopted labor escalation rate.

Account 927
Franchise Requirements

PG&E requests $15,734,000; staff recommends $15,535,000. The staff exceeds PG&E by $199,000.

The reasons for the difference between the staff and PG&E are differing revenue figures, and inclusion by PG&E of the 1983 San Jose franchise fees. PG&E and staff agree on the franchise factor for both electric and gas departments. No estimate of costs for the Sacramento County franchise litigation has been included. As discussed in the policy section of this opinion, we will not include the additional San Jose franchise payments.

We will recognize reasonable franchise fee payments resulting from the Sacramento matter in PG&E's next general rate case proceeding. PG&E may accrue these costs in a separate memorandum account.

Account 928 Regulatory
Commission Expenses

PG&E and staff agree on an expense of $992,000 for this account. We will recognize this amount in the adopted results.

Account 930.2

(1) RD&D

PG&E requests $35,891,000; staff recommends $26,918,000, leaving $8,973,000 at issue. These differences are explained in the RD&D portion of this opinion.

(2) Feasibility Studies

PG&E requests $11,199,000; staff recommends $4,354,000, leaving $6,845,000 at issue.

This concerns PG&E's request for expense treatment of all feasibility studies in the future. This includes preliminary studies for wind, cogeneration, and small hydro projects. There is no change in our policy regarding feasibility studies for projects undertaken by the utility. These will be capitalized when the associated project becomes used and useful. We will adopt the staff estimate which provides for expense treatment of feasibility studies for projects not to be owned by PG&E.

(3) Other Miscellaneous General Expenses

PG&E requests $8,840,000; staff recommends $6,992,000, leaving $1,848,000 at issue. Four items cause this difference:

(a) The staff originally disallowed EEI and AGA dues and contributions of $612,000. The staff witness, after hearing the presentation by EEI's and AGA's witness, recommended that EEI and AGA dues be allowed for ratemaking purposes. However, that change was not reflected in the staff's estimate.

As discussed in the policy section of this opinion, we will allow EEI and AGA dues, less 25% for lobbying activities.

(b) The staff witness recommended disallowance of approximately one-half of other industry association dues of $381,000, on the basis that some of the dues represent contributions to organizations which do not produce benefits to ratepayers. These include nuclear and advertising organizations.

We have found a small number of similar types of organizations to which ratepayer contributions are likewise not appropriate. These include the American Advertising Federation, the American Nuclear Energy Council, and the Institute of Nuclear Power. Factoring out contributions to these types of organizations, we believe it reasonable to allow one-third of PG&E's requested funding. The specific adjustments are consistent with prior decisions.

(c) The staff recommended disallowance of Three Mile Island cleanup costs of $639,000. The staff witness "does not believe that PGandE's ratepayers are getting any benefit from this contribution." (Exhibit 54, p. 10-8.) PG&E included the TMI cleanup costs because it believes that sponsors of Senate Bill 1606 will try again to get it passed in the 98th Congress. PG&E argues that since cleanup payment would be mandated by federal law, the utility would have no choice but to pay the fee. If this legislation does not pass until after the decision in this case is rendered, PG&E submits that the associated costs should be reflected in the 1985 attrition allowance.

We will not allow these costs to be passed on to the ratepayer. We agree with staff that the ratepayer derives no benefit from this expenditure.

(d) Staff recommends disallowance of Equal Employment Opportunity (EEO) litigation expenses in the amount of $125,000 for the electric department, and $62,000 for the gas department. This disallowance represents $80,000 (total utility) for past EEO expenses and another $107,000 (total utility) for future EEO expenses. The reason given by the staff witness for the disallowance is that "the cases are either pending or settled in a way where they are not completely favorable to PGandE."

PG&E argues that this disallowance should be rejected for several reasons. First, the staff witness is not an attorney and has no expertise in judging whether a settlement was favorable or not.

Second, PG&E contends that EEO litigation expenses should be handled in the same way as any other litigation expenses faced by PG&E. Settlement is a normal part of litigation.

PG&E argues that attorneys must make decisions as to whether it is more cost-effective to settle a case or to bring it to trial. Settlement, per se, does not indicate any admission of liability. The decision to settle a case is normally a business decision--that is, the attorneys and management have determined that it is cheaper to settle than to undergo the costs of litigation and the potential for an unfavorable verdict.

Third, according to PG&E, ratepayers benefit from the settlement process by keeping the total dollars for PG&E's litigation costs to a minimum.

Fourth, according to PG&E, its customers also benefit as members of society by keeping the court system operating efficiently and at least cost to taxpayers.

Fifth, PG&E argues that the Commission's decision to treat EEO litigation costs differently than other litigation costs does not make sense. PG&E is involved in numerous law suits. The fact that PG&E is sued does not indicate any liability on behalf of the utility. Plaintiffs often view PG&E as a good defendant due to its size and its vulnerability to jury bias.

Sixth, PG&E points out that under existing Commission policy, PG&E is allowed to ask for recovery of EEO litigation costs in a subsequent general rate case proceeding if it can demonstrate a "successful" resolution of the suit. But no time value of money is provided; so no matter how "successful" PG&E is in defending itself against meritless litigation, the utility still loses.

PG&E recognizes that the dollars involved are relatively small, but the principles are not. PG&E is vitally interested in EEO matters. Corporate policy and corporate actions support equal opportunity for all employees.

PG&E argues that the Commission's understandable concern for EEO issues does not justify an expense treatment policy that is so fraught with problems. PG&E submits that the Commission should reconsider its policy.

As we have done in the past, we will allow reasonably incurred costs of EEO litigation. The reasonable cost of each suit will be included in the general rate case following settlement or conclusion of the proceeding. We will disallow all expenses where PG&E has had to pay punitive damages or where the court has found that PG&E acted in bad faith. Further, the reasonableness of out-of-court settlements will also be examined. We instruct the Executive Director to provide for a legal analysis, as needed, to determine whether future requests for EEO compensation are reasonable.

For purposes of this proceeding, we will adopt PG&E's estimate, less the $107,000 which staff identified as future EEC expenses.

Account 931 Rents

PG&E requests $2,989,000; the staff recommends $2,490,000, leaving at issue $499,000.

Staff claims it has included additional rental costs to accommodate projected employee growth in Account 920. PG&E argues that its estimate was not extrapolated solely from an analysis of A&G needs. The rental estimate includes not only A&G, but also conservation space requirements. It includes all general office staff too. PG&E notes that its figures were produced by the utility's Office Planning Section which takes into consideration space currently available, future reorganizations and how these might affect space needs, and future growth.

We will reduce PG&E's request by 10%. The adopted amount is $2,690,100.

Account 932 Maintenance of General Plant

PG&E and staff agree on $1,337,000.

The only current disagreement between PG&E and staff involves the reporting and record-keeping system that PG&E will use. There is every indication that PG&E and staff will resolve the minor outstanding issues, agree upon a final set of reporting tables, and provide them to the Commission.

The adopted electric department A&G expense is shown on the following table.

Electric Department

ADMINISTRATIVE AND GENERAL EXPENSES

Test Year 1984

(000's Omitted)

Account No.	Description	PGandE	Staff	Adopted
920	Administrative and General Salaries	$84,514	$75,871	$ 76,468
921	Office Supplies and Expenses	45,013	33,711	35,203
922	A. & G. Expenses Transferred - Credit	(22,279)	(32,063)	(27,918)
923	Outside Services	6,275	6,443	6,443
924	Property Insurance	5,352	4,538	5,352
925	Injuries and Damages	17,944	17,944	17,839
926	Employee Pensions and Benefits	137,850	123,653	124,942
928	Regulatory Commission Expense	992	992	992
930	Miscellaneous General Expenses			
	Research, Development and Demonstration	35,891	26,918	26,503
	Feasibility Studies	11,199	4,354	4,354
	Other Miscellaneous General Expenses	8,840	6,992	7,521
	Total Miscellaneous General Expenses	55,930	38,264	38,378
931	Rents	2,989	2,490	2,690
932	Maintenance of General Plant	1,337	1,337	1,337
	Total Excluding Franchises	335,917	273,180	281,726
927	Franchise Requirements	15,734	15,535	14,97[illegible]
	Total Including Franchises (1981 dollars)	$351,651	$288,715	$296,703
	Escalation Amounts			
	Labor	21,623	16,187	16,638
	Nonlabor	14,106	6,179	5,878
	Wage Related A&G	368	98	199
	Total (1984 dollars)	$387,748	$311,179	$319,418

8. Taxes

a. Income Taxes

Apart from numerical differences resulting from differing estimates of expenses and plant, which are resolved elsewhere in this opinion, there was only one issue between staff and PG&E in the income tax area, which we will now address. It concerns the repair allowance used for California corporate franchise tax purposes and the differing estimating techniques used by PG&E and staff to arrive at the appropriate figure.

PG&E witness Young estimated a California franchise tax repair allowance deduction of $26,000,000 for 1984. Staff witness Chow estimated a 1984 repair allowance deduction of $44,709,000. The difference between the utility and staff repair allowance estimates is due to the historical data used in estimating. PG&E, after it prepared its estimate, informed the staff that a mistake was found in the data. Staff corrected for this error; however, staff and PG&E's estimates are far apart due to different estimating methods. The PG&E witness and staff witness are both adamant that their respective positions are correct. We will split the difference. The adopted repair allowance for test year 1984 is $35,354,000.

There is one other item in the income tax area which we will address.

The federal Tax Equity and Fiscal Responsibility Act (TEFRA) was signed into law on September 3, 1982. TEFRA resulted in several changes in federal income tax law which effectively increase the income tax expense of PG&E. Both the staff and PG&E agree on the methodology for implementing the ratemaking effects of TEFRA. With one exception, all TEFRA changes are reflected in 1984 general rate case estimates of both the utility and the staff.

The sole TEFRA change which was not incorporated in either PG&E or the staff 1984 general rate case estimates pertains to new rules under IRC Section 189 which preclude the utility from obtaining a current tax deduction for certain interest and property taxes associated with real property construction. Instead, the staff and PG&E have agreed to recommend that the Commission decision specifically provide for PG&E to be reimbursed in future general rate cases for revenue requirments properly attributable to 1984 and 1985 which arise solely from costs incurred as a result of this specific tax law change. The staff and PG&E recommend this special rate procedure because uncertainty exists over the correct interpretation of the changes made by TEFRA to IRC Section 189, and it is likely that clarifying tax regulations will be promulgated in the near future which will resolve this uncertainty.

We agree. PG&E is authorized to establish a separate memorandum account for future collection of all 1984 and 1985 revenue requirements associated solely with this specific TEFRA change to IRC Section 189. Our adopted income taxes will reflect the appropriate deductions corresponding to our adopted expenses, plant and rate base estimates.

b. Property Taxes

PG&E's estimate of 1984 test year property taxes assigned to the Electric Department is $66,717,000 while the staff estimate is $66,104,000. The difference is $613,000.

PG&E estimates property taxes assigned to the Gas Department for test year 1984 to be $15,322,000. Staff estimates $15,219,000. The difference is $103,000.

The differences in staff and utility estimates of property taxes for both the Electric and Gas Departments are caused by differences in plant, depreciation reserve, and rate base other than working cash estimates for the respective departments.

The adopted property taxes will reflect our adopted estimates of plant.

c. Payroll and Business Taxes

For the Electric Department PG&E has requested $33,474,000; the staff recommends $30,090,000, leaving $3,384,000 at issue.

For the Gas Department PG&E has requested $15,920,000; the staff has recommended $14,308,000, leaving a difference of $1,612,000. Estimation techniques are the same for both the Electric and Gas Departments.

There is no difference between the staff and PG&E in their estimating methodology. The dollar difference between the estimates is caused by differences in estimated employee growth and wages. The adopted payroll taxes will be based on the employee growth and wages reflected in this opinion.

After PG&E's application was filed, the Federal Government enacted a change to the FICA rates for 1984 that will increase the utility's expense for FICA taxes. (Tr. 2497.) We will reflect this change in the adopted tax calculation.

By letter dated November 15, 1983 (late-filed Exhibit 260), PG&E informed the Commission and all parties of record that employee benefits, payroll taxes, and workers compensation expenses related to the Zero Interest Program (ZIP) and Residential Conservation Service Program (RCS) should be removed from the 1984 general rate case since PG&E has included these in its consolidated ZIP and RCS proceeding (A.83-08-65 and A.83-08-66). We will reflect this reduction in the adopted amount.

The adopted taxes are set forth in the following tables.

Electric Department

COMPUTATION OF INCOME TAXES

1984 Present Rates
(000's Omitted)

Description	PG&E	Staff	Adopted
Operating Revenues	$2,171,850	$2,312,873	$2,229,473
O&M Expenses	1,099,927	916,528	932,866
Taxes Other Than Income	99,442	96,610	97,467
Subtotal	972,481	1,299,735	1,199,140
Deductions from Taxable Income			
Operating Expense Adjustments	10,238	420	420
Interest Charges	251,122	245,752	248,356
Capitalized Pensions & Benefits	36,628	33,223	33,666
Capitalized Ad Valorem Taxes	1,505	1,505	1,503
Use Taxes	1,488	1,488	1,488
Fiscal/Calendar Adj.	2,143	1,530	1,530
Subtotal Deductions	303,124	283,918	286,963
CCFT Taxes			
CCFT Depreciation	255,729	253,628	254,428
Removal Costs	9,814	9,818	9,818
Repair Allowance	24,700	42,474	33,586
Subtotal Deductions	593,367	589,838	584,795
Taxable Income for CCFT	379,114	709,897	614,345
CCFT	36,395	68,150	58,977
State Tax Adjustment	47	47	47
Current CCFT	36,442	68,197	59,024
Defense Facilities Credit	(151)	(151)	(151)
Deferred Taxes (CCFT)	2,420	0	0
Total CCFT	$ 38,711	$ 68,046	$ 58,873
Federal Taxes			
Current CCFT	36,442	68,197	59,024
Federal Tax Depreciation	220,390	219,292	219,831
Preferred Divid. Credit	1,657	1,667	1,667
Subtotal Deductions	561,623	573,074	567,485
Taxable Income for FIT	410,858	726,661	631,655
Federal Income Tax	188,995	334,264	290,561
Graduated Rate Benefit	(13)	(13)	(13)
Defense Facilities Credit	(1,419)	(1,419)	(1,419)
Deferred Taxes (FIT)	10,480	0	0
FIT Before Adj.	198,043	332,832	289,129
Investment Tax Credit	0	0	0
Total FIT	$ 198,043	$ 332,832	$ 289,129

Electric Department

PROPERTY TAX EXPENSES

Test Year 1984

(000's Omitted)

Description	PGandE	Staff	Adopted
Property Tax Expense	$66,717	$66,104	$66,110
Total	$66,717	$66,104	$66,110

Pacific Gas and Electric Company
Electric Department

PAYROLL TAXES
Test Year 1984

Description	PG&E	Staff	Adopted
FICA (Tax Rate = 7%)	$28,143	$26,230	$26,964
FUI	895	835	858
SUI	1,882	1,754	1,803
S.F. Employee Tax	1,742	1,624	1,669
Business Tax	63	63	63
Total (1981 Dollars)	$32,725	$30,506	$31,357
Escalation Amounts			
Labor	5,893	5,493	5,647
Total (1984 dollars)	$38,618	$35,999	$37,004

9. Depreciation Expense

PG&E and staff agree on the depreciation elements (average service lives, mortality curve types, net salvage rates, and remaining lives) that are used to calculate depreciation expense for the test year. The difference is due to differing estimates of load management capital expenditures and plant additions for 1983 and 1984, as well as differences between the utility and staff on the PCB Transformer Replacement Program. These matters are resolved elsewhere in this opinion. The adopted depreciation expense reflects our resolution of these issues.

10. Plant and Rate Base

Electric plant and electric rate base excluding working cash are reviewed together due to the interrelationship of the two subjects. The rate base estimates of PG&E and staff are set forth below:

	PG&E	Staff	PG&E Exceeds Staff
	(Thousands of Dollars)		
Electric Rate Base With Working Cash	$5,584,470	$5,508,163	$76,307
Working Cash	110,974	106,369	4,605
Electric Rate Base Other Than Working Cash	$5,473,496	$5,401,794	$71,702

Electric Department

DEPRECIATION EXPENSE

Test Year 1984

(000's Omitted)

Description	PGandE	Staff	Adopted
Electric Department	$303,684	$299,708	$300,244
Common Utility Allocation	13,425	13,295	13,333
PCB Transformer Replacement Program	428	428	428
Bay Point	41	41	41
Street Light Sales (Adjustment)	(143)	(143)	(143)
Changes in Line Extension Rules (Adjustment)	(977)	(977)	0
Kerchkhoff	97	97	97
Total	$316,555	$312,449	$314,000

The items making up the difference of $71,702,000 in Electric Rate Base Excluding Working Cash are detailed below:

	PG&E	Staff	PG&E Exceeds Staff
	(Thousands of dollars)		
RD&D and Feasibility Studies	$ 53,984	$ 0	$53,984
Load Management	55,404	28,376	27,028
Depreciation Reserve	(2,925,318)	(2,917,986)	(7,332)
AFUDC Adjustment	0	(2,588)	2,588
Computer Capital Allocated to Elec. Dept.	4,762	4,089	673
Deferred ITC Deducted From Rate Base	(115,346)	(112,841)	2,505
21 kV Conversion Program	7,956	3,799	4,157
Total			71,702

The adopted rate base reflects current line extension rules.

We will discuss these differences.

a. RD&D and Feasibility Studies

We have already discussed our treatment of these expenditures in the policy section of this decision. The amount included in the electric department rate base is set forth in the following table:

Electric Department

1984 AMORTIZATION OF FEASIBILITY STUDIES AND RDandD a/

(000's Omitted)

Category	PGandE	Staff	Adopted
RDandD			
Ongoing Projects b/	$ 8,888	$ 6,665	$ 6,665
Completed Projects b/	596	375	375
Feasibility Studies			
Projects in the Long-Term Plan	6,536	0	
Suspended Projects	30,854	18,747 c/	15,171 c/
Utah Coal Sale Gain	0	(7,302) d/	-0-
TOTAL ELECTRIC DEPARTMENT	$46,874	$18,485	$22,211

(Red Figure)

a/ Amortization over four-year period.

b/ No AFUDC allowed.

c/ No AFUDC allowed. Excludes direct cost of Montezuma. Direct cost amortized over four years.

d/ Pulsifier recommendation.

b. <u>Load Management Capital</u>

PG&E's estimate for this item is $55,404,000, while the staff recommends $28,376,000. This item is covered in the Load Management section of this opinion. The adopted rate base includes $24,179,000 for capitalized cost for 1984 additions.

c. <u>PCB Transformer Replacement Program</u>

PG&E estimates the rate base impact of the PCB Transformer Replacement Program as $7,185,000. Staff subsequently adopted PG&E's estimate. We will include this amount in the adopted rate base.

d. <u>Depreciation Reserve</u>

The difference in depreciation reserve for 1984 is the result of different estimates of plant in the following areas: Load Management Capital, AFUDC Adjustment, and the Electric Department allocation of computer-related capital. All other depreciation reserve differences are directly related to the differences in other rate base items.

PG&E and staff agree on the depreciation elements (average service lives, mortality curve types, net salvage rates, and remaining lives) that are used to calculate the utility's depreciation expense for the test year.

e. AFUDC Adjustment

In Exhibit 52, the Staff Results of Examination report, the staff auditors make four recommendations for adjustments to AFUDC accrued during the years 1979 through 1982.

PG&E stipulates to the first adjustment but contests the remaining three adjustments. PG&E did not cross-examine staff witness Abraham Hitti on his recommendations but rather offered rebuttal testimony through PG&E witness Gloria Gee in Exhibit 226.

The staff's second recommendation is that AFUDC accrued in 1982 should be reduced by $2,078,000 to reflect the inclusion of balancing account overcollections as a source of short-term funds. We agree with staff that PG&E's position is inconsistent with its past treatment of its balancing account undercollection with respect to its AFUDC calculation. As pointed out by staff, over- and undercollections affect PG&E's cost of construction capital in similar ways and should be accorded similar accounting treatment. For that reason, we will include balancing account overcollections in the calculation of AFUDC for 1982 in the same fashion that PG&E has previously included undercollection balances.

The third recommendation of the staff auditors involves an adjustment of the AFUDC rate for 1979 to reduce the AFUDC accrued during that year by $5,626,000 to comply with D.93887 dated December 30, 1981. PG&E concurs with only a $433,000 adjustment.

We agree with staff that PG&E maximized the 25 basis point tolerance band in a fashion which does not comport with the intent of FERC Order 561. Accordingly, we adopt staff's recommendation.

As the final staff recommendation, the staff auditor would reduce AFUDC accrued during 1980 by $6,106,000 to comply with D.93887. PG&E agrees with only $1,593,000 of that adjustment. In 1980, PG&E made an estimate in a manner very similar to that for 1979, which included a mechanical calculation of the AFUDC rate resulting in an 8.53% rate and then additional judgment was used to raise the rate to 8.87%.

PG&E argues that FERC completed an audit of its books and for that reason, we should accept PG&E's AFUDC calculations as being in compliance with FERC. In the absence of a specific finding by FERC on this AFUDC issue, we reject PG&E's argument. The mere fact that there was an audit by FERC and no exceptions were noted on this matter is not conclusive that FERC did consider the issue in question.

Accordingly, we adopt the staff recommendation on this matter.

f. Computer Capital

As discussed below under Common Plant, we adopt PG&E's estimates of computer-related equipment for 1984 and 1985, less a 10% adjustment.

g. 21 kV Conversion Program Capital

As discussed under Transmission and Distribution Efficiency Measures, we adopt PG&E's estimate which includes $7,956,000 in rate base for this program.

h. Deferred Income Taxes and Deferred Investment Tax Credit

The differences are due to differing plant estimates which we discussed previously. The adopted amount will reflect the adopted plant estimate.

i. Working Cash

PG&E requests $114,505,000, the staff recommends $108,897,000, leaving a difference of $5,626,000.

$4,569,000 of this difference relates to the appropriate expense levels and escalation rates for 1984.

The remaining difference of $1,057,000 reflects the prepaid unamortized balance of all-risk insurance coverage for Diablo Canyon. PG&E requests the $1,057,000 be placed in the working cash allowance. The staff recommends that the $1,057,000 be recovered in the Diablo Canyon rate case offset proceeding instead of in the general rate case.

PG&E argues that Diablo Canyon's prepaid insurance has been included in the working cash allowance for at least the last three general rate cases. PG&E submits that unless the Commission orders the utility to capitalize the full insurance premium, PG&E will have no other means of recovering the premium cost other than in the working cash allowance. Both PG&E and staff also agree that the costs associated with prepaid insurance are a legitimate cost which should be recovered from the ratepayer.

We agree with staff. The prepaid insurance should be capitalized and recovered in the Diablo Canyon offset proceeding.

j. Common Plant

The difference in Common Utility Plant estimates is the result of disagreement on one item, computer-related equipment. PG&E estimates expenditures for computer-related equipment in 1984 at $21,500,000, while the staff estimates the cost at $16,497,000. The difference in expenditures of $5,003,000 reflects a dispute between PG&E and the staff concerning the appropriate number of personal computers and word processing machines ("Office Technology Equipment") that will be purchased and included in the calculation of rate base in the test year.

PG&E estimates total 1984 capital cost of this equipment at $6,400,000, while the staff estimates the cost at $1,397,000.

PG&E witness O'Flanagan testified that PG&E's Computer Systems and Services (CS&S) Department prepared PG&E's estimate of Office Technology Equipment capital after a detailed analysis concerning the cost-effectiveness of the use of this equipment. PG&E provided Exhibits 165 and 166 in support of the reasonableness of its request.

While PG&E cited passages from the CMP audit report indicating that the CS&S Department was a highly cost conscious organization as of the date of the report in 1980, staff argues that audit report is no guarantee that the department will remain such a frugal and cost conscious organization in the future. Also, according to staff, at some point the utility's expenditures for computer-related equipment will have to reach a saturation point and it is the position of the staff witness that installation of computer-related equipment should proceed at a measured pace so that the utility does not purchase equipment which is not cost-effective. Staff is also conscious of the fact that personal computers and word processors can be prestige items in an office environment and is guarding against the phenomenon of purchasing equipment for personnel when it is not really needed. Staff also notes that the survey which the utility used to estimate its needs for computer-related equipment did not specifically request of the survey recipients any calculation as to the dollar savings that would be achieved by the use of such equipment. It simply asked for a general description of how additional capabilities or equipment might improve productivity. In light of this fact, staff argues that it is not unreasonable to require the utility to gain additional experience in the use of such equipment before widely distributing it throughout the utility.

We note staff's concerns. However, we also note PG&E's witnesses testified that PG&E is anticipating productivity improvements resulting from this equipment and has reflected such cost savings in its showing. We believe it is reasonable that PG&E be given the necessary tools to do the job but PG&E should be able to get by on less. In authorizing the expenditure requested by PG&E, we do expect to see, in PG&E's next general rate case proceeding, an accounting summary of this equipment purchase program and some quantification of the savings achieved.

We will adopt the expenditure levels requested by PG&E for purchase of Office Technology Equipment for 1984 and 1985 reduced by 10%.

11. <u>Summary of Earnings</u>

The Comparison Exhibit delineates the differences between the staff's and PG&E's results of operations for the Electric Department. Both PG&E and the staff estimate Electric Department results of operations on a total Electric Department basis and then separate this total into results of operations subject to the jurisdiction of the Commission and results of operations subject to the jurisdiction of the FERC. We will reflect the allocations resulting from the staff estimate of Resale Sales.

The following tables summarize the key components of PG&E's results of operations as adopted for the test year.

12. <u>Jurisdictional Allocation</u>

Since we have adopted the staff's sales estimates, our allocation of total system operations to CPUC jurisdictional operations reflects the staff's jurisdictional factors.

13. <u>Attrition</u>

The policy on financial and operational attrition is set forth at Chapter III Section K and Chapter IV Section A.6.

The table on page 86 sets forth the attrition allowance calculation.

Electric Department
WEIGHTED AVERAGE RATE BASE
Test Year 1984
(000's Omitted)

Description	PG&E	Staff	Adopted
Weighted Average Electric Plant			
Electric Plant	$8,093,847	$8,060,074	$8,072,805
Electric Plant Held for Future Use	35,552	35,552	27,864
Common Plant - Allocation	439,705	439,032	439,229
Common Plant Held for Future Use	378	378	378
Total Weighted Average Electric Plant	8,569,482	8,535,036	8,540,276
Working Capital			
Materials and Supplies	55,240	55,240	55,240
Working Cash	110,974	106,369	110,229
RD&D and Feasibility Studies	53,984	0	0
Total Working Capital	220,198	161,609	165,469
Less Adjustments			
Customer Advances	68,308	68,308	68,308
Accumulated Deferred Taxes - Defense	17,530	17,530	17,530
Accumulated Deferred Taxes - ACRS	81,228	74,337	79,408
Deferred I.T.C.	115,346	112,841	114,024
Line Extensions	8,505	8,505	0
Bay Point Power and Light	(961)	(961)	(961)
Street Lights Sales	1,430	1,430	1,430
S.F. D.C. Substations	1,260	1,260	1,260
PCB Transformer Replacement	(8,285)	(8,285)	(8,285)
Kerckhoff	(4,469)	(4,469)	(4,469)
Total Adjustments	279,892	270,496	268,245
Depreciation Reserve	2,925,318	2,917,986	2,918,478
Total Rate Base	$5,584,470	$5,508,163	$5,519,022

Electric Department

WORKING CASH CAPITAL
DETERMINATION OF WORKING CASH CAPITAL
SUPPLIED BY INVESTORS

Test Year 1984

(000's Omitted)

Description	PGandE	Staff	Adopted
Operational Cash Requirement			
Required Bank Balance	$34,740	$34,740	$34,740
Special Deposits and Working Funds	593	593	593
Prepayments	2,608	2,608	2,608
Deferred Debits, companywide	(9,352)	(9,352)	(9,352)
Subtotal a/	19,037	19,037	19,037
Prepayments, Electric Department	2,038	981	981
Total Operational Cash Requirement	21,075	20,018	20,018
Plus: Working Cash Capital Requirement from Lead Lag Study	138,256	134,709	140,632
Less: Accrued Vacation a/	36,967	36,967	39,031
Total Working Cash Capital Requirement	122,364	117,760	121,619
Less: Working Cash Capital Not Supplied by Investors a/	11,390	11,390	11,390
Working Cash Capital Supplied by Investors	$110,974	$106,370	$110,229

a/ Represents 66.59% allocation to the Electric Department.

Pacific Gas and Electric Company
Electric Department

ADOPTED SUMMARY OF EARNINGS

Test Year 1984
At Present and Authorized Rates
(000's Omitted)

	PRESENT RATES		ADOPTED 1/
	Total Department	CPUC Jurisdictional	CPUC Jurisdictional
Operating Revenues	$2,229,473	$2,177,478	$2,472,665
Operating Expenses			
Production	161,502	157,473	157,473
Nuclear Disposal	1,824	1,771	1,771
Transmission	26,462	22,781	22,781
Distribution	175,002	174,116	174,116
Customer Accounts	74,227	74,044	74,785
Customer Service and Info.	39,237	39,237	39,237
Load Management	16,837	16,837	16,837
Admin. & General	296,703	291,168	293,156
Feas. & RD&D Amortization	22,211	21,593	21,593
Subtotal	814,005	799,020	801,749
Labor Escalation	91,047	89,390	89,390
Nonlabor Escalation	27,814	27,334	27,334
Subtotal after Adjustment	932,866	915,744	918,473
Book Depreciation	314,000	305,808	305,808
Taxes Other Than Income	97,467	94,713	94,713
State Corp. Franchise Tax	58,873	57,506	85,582
Federal Income Tax	289,129	282,216	403,832
Total Operating Expenses	1,692,335	1,655,987	1,808,408
Net Operating Revenues	537,138	521,491	664,258
Rate Base	5,519,022	5,335,404	5,335,404
Rate of Return	9.73%	9.77%	12.45%

1/ Authorized revenue increase of $295,187,000 reduced by $22,996,000 refund of unexpended conservation-load management funds. Revenue increase also reduced by $43,442,000 estimated 1983 ERAM overcollection

C. Gas Department
Results of Operations

1. Revenues

The staff and PG&E reached a stipulation on test year estimated sales and revenues for the gas department. There remain no differences between the staff and the utility in this regard. (Ex. 259, p. 4-1 and 4-2.) The adopted sales and revenue estimates are set forth in the following tables:

Gas Department

SALES AND OTHER SENDOUT

Test Year 1984

(000's of Decatherms)

Sendout Category	PGandE	Staff	Adopted
Residential	203,034	203,034	203,034
Commercial and Industrial			
P1 and P2	139,259	139,259	139,259
P3 and P4	128,020	128,020	128,020
Total Commercial and Industrial	267,279	267,279	267,279
So. Cal. Edison (Coolwater)	15,209	15,209	15,209
Resale	8,121	8,121	8,121
Interdepartmental			
Steam Heat Plants	920	920	920
Steam Electric Plants	274,500	274,500	274,500
Construction and Clearing	82	82	82
Other Operations	185	185	185
Total Interdepartmental	275,687	275,687	275,687
Total Sales	769,330	769,330	769,330
Incidental Sendout			
Gas Used by Gas Department	4,382	4,382	4,382
Losses and Unaccounted-For	18,716	18,716	18,716
Total Incidental	23,098	23,098	23,098
Total Sales and Other Sendout	792,428	792,428	792,428

Gas Department

ESTIMATED REVENUES AT PRESENT RATES*

Test Year 1984

(000's Omitted)

Class of Service and Schedule	PGandE	Staff	Adopted
Residential			
Tier I	$ 624,286	$ 624,286	$ 624,286
Tier II	244,752	244,752	244,752
Tier III	65,423	65,423	65,423
Total Residential	934,461	934,461	934,461
Nonresidential			
G-2(2)	781,681	781,681	781,681
G-50(3)	360,705	360,705	360,705
G-52	315,695	315,695	315,695
G-55A	66,895	66,895	66,895
G-55	1,455,509	1,455,509	1,455,509
G-57	40,356	40,356	40,356
Total Nonresidential	3,020,841	3,020,841	3,020,841
Resale			
G-60	14,415	14,415	14,415
G-61-63	21,434	21,434	21,434
SoCal Gas	0	0	0
Total Resale	35,849	35,849	35,849
Total from Sales	3,991,151	3,991,151	3,991,151
Other Operating Revenue	3,600	3,600	3,600
Total Base Plus GAC**	3,994,751	3,994,751	3,994,751

* Rates in effect 4/6/83.

** Excludes GEDA and SFA revenues and includes CFA and RCS revenues.

2. Production Expenses

The differences between PG&E and staff concerning Gas Production Expenses are solely related to different escalation rates.

a. Cost of Gas

PG&E's request in current 1984 dollars is $45,098,000; the staff recommends $44,670,000, leaving $428,000 at issue. This difference results from the use of different labor, and materials and services escalation rates by the utility and the staff. The adopted Pacific Gas Transmission Company (PGT) cost of service estimate will reflect the adopted escalation rates.

b. Gas Production Expenses

The following table sets forth the adopted gas production expenses.

Gas Department

PRODUCTION EXPENSE - COST OF GAS
PGT COST OF SERVICE

Test Year 1984

(000's Omitted)

Description	PGandE	Staff	Adopted
Pacific Gas Transmission -- Cost of Service	$44,872	$44,670	$44,770

Gas Department

PRODUCTION EXPENSES

Test Year 1984

(000's Omitted)

Account No.	Description	PG&E	Staff	Adopted
	OPERATION			
710	Operation Supervision and Engineering	$ 6	$ 6	$ 6
717	Liquefied Petroleum Gas Expense	0	0	0
733	Gas Mixing Expenses	9	9	9
735	Miscellaneous Production Expenses	97	97	97
798	Other Exploration and Development Expense	0	0	0
807.20	Purchased Gas Measuring Expenses	439	439	439
807.40	Purchased Gas Calculation Expenses	570	570	570
807.50	Other Purchased Gas Expenses	200	200	200
813	Other Gas Supply Expenses	32	32	32
	Total Production Operation Expenses	1,353	1,353	1,353
	MAINTENANCE			
740	Supervision and Engineering	4	4	4
741	Structures and Improvements	1	1	1
742	Production Equipment	78	78	78
	Total Production Maintenance Expenses	83	83	83
	Total Production Expenses (1981 Dollars)	$1,436	$1,436	$1,436
	Escalation Amounts			
	Labor	277	281	281
	Non-Labor	57	34	38
	Total (1984 Dollars)	$1,770	$1,751	$1,755

3. Gas Storage Expenses

In 1981 dollars, PG&E's estimate of total storage expenses of $9,584,000 exceeds the staff's estimate of $7,202,000 by $2,382,000. The major differences between utility and staff are summarized in the following table:

Pipeline Operations Staffing Levels	$ 55,000
Estimating Techniques	1,333,000
Deferred Maintenance	818,000
Wireline and Leak Surveys	30,000
Pipeline Stress Relief	146,000
Total	$2,382,000

a. Pipeline Staffing Levels

In D.93887, the Commission allowed PG&E cost recovery for additional pipeline operations manpower needed to operate the McDonald Island and the new Los Medanos underground gas storage fields. In this proceeding, PG&E used 1981 recorded costs as the base estimate. Since the 1981 recorded costs do not include the new Pipeline Operations positions, PG&E made adjustments to the base 1981 figures.

According to PG&E, five additional operator mechanics are required: three at McDonald Island and two at Los Medanos. There are currently six operators at each facility. PG&E contends that the additional manpower will allow two-operator-per-shift staffing.

PG&E notes that these major gas storage facilities provide up to 1/3 of the system's gas supply on cold winter days, when gas usage peaks. PG&E submits that the remote locations of these fields, their complexity, and the requirement for operators to perform duties away from their control stations, warrant two-operator-per-shift staffing.

The staff allowed only three of the five operator mechanic positions on the ground that a trend of expenses which met the staff's statistical tests showed that a level of expense would be expected in the test year that approximated the addition of only three of five positions.

We conclude that PG&E's proposed staffing of two operators per shift is reasonable. We will adopt PG&E's estimate.

b. Estimating Techniques

Estimating technique differences account for $1,433,000 of the disparity between PG&E and staff estimates for Storage Expense.

PG&E's estimated storage expenses for the years 1982 through 1984 were derived from actual recorded base year 1981 expenses. According to PG&E this method was selected because 1981 recorded data was the most representative of current operating conditions, management decisions and regulatory code compliance. Consequently, recorded 1981 expenses were used as a base on which adjustments were made to reflect estimates for costs which were considered to be special and/or nonrecurring. For example, the Pipeline Operations positions discussed above were treated as an adjustment.

Staff trended all accounts for gas maintenance and operating expenses except for PGT cost of service. If the R-Squared was below 0.6, staff used a different method. PG&E argues that in using this statistical approach, staff did not consider the specific changing environment of PG&E's gas operation and maintenance activities.

We will not adopt a blanket approach to deciding O&M expenses based on estimating technique. The adopted expense will be based on an account by account review.

c. Deferred Maintenance

Deferred maintenance accounts for $818,000 of the difference between PG&E and staff. PG&E's witness testified that the utility's decision to perform maintenance on higher priority items, while deferring lower priority matters, did not cause a deterioration in plant efficiency.

As discussed previously, all funding for deferred maintenance is disallowed.

d. Review of Specific Accounts

We will review the accounts where there is a difference between PG&E and staff. We will not discuss the accounts where the only differences are due to escalation rates or deferred maintenance but will reflect the adopted escalation rates and disallowance of deferred maintenance in the adopted summary of earnings.

Account 818 Compressor Station Expenses

PG&E requested $322,000; the staff recommends $267,000, leaving $55,000 at issue. The only cause of the difference between utility and staff estimates is pipeline operations staffing levels amounting to $55,000. As discussed previously, we will adopt PG&E's estimate.

Account 819 Compressor Station Fuel and Power

PG&E requested $3,693,000; the staff recommends $3,370,000, leaving $323,000 at issue. Estimating differences related to forecasting both injection rates into McDonald Island and the unit cost of electricity per million cubic feet injected cause this $323,000 difference.

PG&E's position is that forecasted injection volume is a direct result of the supply-demand balance predicted for 1984 in the latest Fuels Management Outlook. According to PG&E, the volume of gas available in 1984 from Canada, El Paso, and California were considered.

Winter peak gas usage is proportional to underground gas storage field withdrawal and results in summer injection to restore the field. Annual sales have no direct bearing on injection volume.

To determine the cost of electricity used to inject gas into storage, PG&E developed its rate by using actual 1981 recorded metered costs per actual volume of gas injected. To reflect 1984 costs, this unit cost was increased using percentage increases in forecasted rate schedule A-23, Large Light and Power.

Staff based its estimates on averages of 1977-81 historical data of both the volume of gas to be injected and the unit cost of electricity used to inject that gas.

We agree with PG&E that it is more appropriate to base test year power costs on the 1984 supply-demand forecast. However, because of current reductions in electric rates due to favorable hydro conditions, we will use the 1982 recorded rate of 74.2 mills/kWh.

Account 820 Measuring and Regulating Station Expense

PG&E requested $266,000; the staff recommends $205,000, leaving $61,000 at issue. The difference between utility and staff's estimates results from the Los Medanos Storage Field becoming operational in late 1981.

PG&E included an additional $52,000 over 1981 base level of expenditures in this account. The staff's position is that the account on a five-year recorded basis is experiencing a downward trend and that this trend will continue. According to PG&E with the addition of the Los Medanos field, the downward trend will not continue, but rather, an increase in the account will be experienced due to this major facility addition.

Staff contends that the utility would be able to absorb the additional expenses of operating the Los Medanos field with the funding which it has and will receive.

We will adopt PG&E's estimate.

Account 823 Gas Losses

PG&E requested $923,000; the staff recommends no funding for this account. Staff would disallow any cost recovery related to the gas lost at the Los Medanos Underground Storage Field. The staff witness argued that D.82-12-054 dated December 8, 1982 in the last Southern California Gas Company (SoCal Gas) General Rate Case forbids the recovery of past gas losses, but may permit recovery of normal operational (projected) gas losses.

PG&E sustained a loss in 1982 at its newly opened Los Medanos storage field due to leakage in a stage collar at the surface of the well. This leak was not due to gradual migration or slow leakage of gas from the storage field through the porous rock formations underground, but was due to a mechanical failure, an accident on the surface. PG&E proposes in its rate increase application that it should recover over a two-year period the sum total of the gas lost through the accident.

At the same time that PG&E filed its application in this proceeding, the Commission issued D.82-12-054 in the SoCal Gas general rate case proceeding, A.61081. That decision dealt with gas losses for which SoCal Gas had proposed recovery. PG&E did not revise its request as the result of reading the SoCal Gas decision. The staff submitted its recommendation which essentially is that the utility may not recover for a loss prior to the test year in a general rate case proceeding.

Accordingly, PG&E filed a supplemental exhibit changing its request from one which requests all of the past gas losses over a two-year period to three alternatives which would allow different ratemaking treatment for gas losses.

We agree that PG&E took prompt action to correct the gas leak, and we commend PG&E for its diligence; however, as PG&E is well aware, we do not allow recovery for past losses or expenditures if it is not included in the test year. Accordingly, there will be no recovery for PG&E's past losses.

But we agree that PG&E should have a mechanism for recovery on a prospective basis for future losses. Simply because there was only one gas loss in five years is no reason to deny PG&E such a mechanism for recovery for losses in the future. If there is no mechanism in place PG&E will again be foreclosed from recovery if there is another such leak.

PG&E suggested three alternative ratemaking treatments for gas losses from storage facilities that the Commission might adopt:

1. Allow PG&E to estimate its gas losses of this type on a prospective basis as the Commission allowed in D.82-12-054 for SoCal Gas.
2. Add Account 823, Gas Losses, to those accounts included in the Gas Adjustment Clause preliminary statement, part c.
3. Permit the company to adjust its quantity of gas stored underground for such gas losses thereby slightly increasing the average cost of gas stored underground. (Ex. 234, p. 1.)

According to PG&E, any of these three methods would be acceptable.

We prefer an approach that results in recovery of actual losses. We will authorize PG&E to add Account 823, Gas Losses, to those accounts included in the Gas Adjustment Clause commencing in 1984. It should be noted that the utility has the burden of demonstrating that it took all reasonable steps to minimize such losses.

We will adopt the staff recommendation of no funding for this account in this general rate proceeding.

Account 825 Storage Well Royalties

PG&E requested $174,000; the staff recommends $163,000, leaving $11,000 at issue. PG&E argues that the reason for the difference is the addition of a third major royalty paid by the utility. PG&E's position is that there are now three major royalties to be paid due to the Los Medanos Field becoming operational in October 1981, and that the State Lands Commission lease increases by 5% each year through March 1, 1984.

These fee arrangements have mechanisms for adjusting the royalties upwards, but the staff disagrees with the use of the utility's labor and nonlabor escalation rates on the ground that they are excessive for the period of the test year.

We will adopt PG&E's estimate adjusted to reflect the adopted escalation rates.

Account 842.2 Power

PG&E requested $207,000; the staff recommends $135,000, leaving $72,000 at issue. The reason for the difference is estimating technique. The utility's estimate is based on 1981 recorded expenses and its position is that 1981 expenses are most representative of future costs. According to PG&E, the 1981 recorded expenditure of $207,000, and the 1982 recorded figure of $214,000 are representative of current operating levels.

We will adopt PG&E's estimate.

Account 832 Reservoirs and Wells

PG&E requested $202,000; the staff recommends $172,000, leaving $30,000 at issue. The reason for the difference is the forecasting methodology used for determining annual wireline survey expenses.

The utility's position is that the California Department of Oil and Gas is now requiring annual surveys at gas underground storage fields.

The staff's approach is to base its estimate on recorded data. However, the staff witness did agree that the utility should be provided with funds to perform the mandated surveys.

We will adopt PG&E's estimate.

Account 833 Lines

PG&E requested $60,000; the staff recommends $14,000, leaving $46,000 at issue. The reason for the difference is pipeline stress relief work to be performed on the gathering lines at the McDonald Island platforms.

PG&E's position is that this stress relief work is necessary. PG&E takes exception to the staff proposal to allow the transmission stress relief work on lines 57A and 57B, but disallow the storage stress relief work on the gathering lines.

We agree with PG&E that it is more productive to perform stress relief work on the storage and transmission lines at the same time, rather than at different periods. Accordingly, we will adopt PG&E's estimate.

Account 834 Compressor Station Equipment

PG&E requested $205,000; the staff recommends $101,000, leaving $104,000 at issue. The reason for the difference centers on compressor overhauls at Brentwood and McDonald Island. The overhauls are normally done every 7 years. The McDonald Island compressor overhauls were last done in 1976. According to PG&E, these compressors need to be overhauled to assure 100% reliability of the McDonald Island Underground Gas Storage Field.

The staff's position is that the overhauls are deferred maintenance. The staff witness does agree that major overhauls on compressors are necessary. He also agreed that rescheduling the overhaul of the K-2 compressors had no effect on the reliability or efficiency of the system.

As stated previously, we will not provide funding for deferred maintenance. We will adopt the staff adjustment.

Account 835 Measuring and Regulating Station Equipment

PG&E requested $264,000; the staff recommends $255,000, leaving $9,000 at issue. The utility's estimate was based on 1981 recorded expenses, modified using adjustments for specific programs. According to PG&E this method is most representative of current operating conditions. The staff witness used a four-year average (1978-81) which, PG&E argues, does not represent current conditions.

We will adopt PG&E's estimate.

Account 836 Purification Equipment

PG&E requested $92,000; the staff recommends $69,000, leaving $23,000 at issue. The reason for the difference is the expense associated with the Los Medanos Underground Storage Field. PG&E's position is that the increase is necessary due to the addition of the Los Medanos Storage Field - a large gas underground storage field which occurred in late 1981.

PG&E argues that staff used recorded 1981 data which does not reflect the annual costs of operating the Los Medanos Field.

We will adopt PG&E's estimate.

Account 837 Other Equipment

PG&E requested $619,000; the staff recommends $614,000, leaving $5,000 at issue. The staff estimate reflects a lower estimate because there was an error in PG&E's workpapers which PG&E subsequently corrected. We will adopt PG&E's estimate.

Account 843.1 Supervision and Engineering

PG&E requested $51,000; the staff recommends $46,000, leaving $5,000 at issue. PG&E's estimate was based on 1981 recorded expenses, modified using adjustments for specific programs. PG&E argues that this method is most representative of current operating conditions. The staff used a four-year average which, according to PG&E, is not as representative of current conditions.

We will adopt PG&E's estimate.

Account 843.2 Structures and Improvements

PG&E requested $74,000; the staff recommends $73,000, leaving $1,000 at issue. PG&E used 1981 recorded expenses. The staff relied on a four-year average.

We will adopt PG&E's estimate.

Account 843.3 Gas Holders

PG&E requested $372,000; the staff recommends $292,000, leaving $80,000 at issue. The difference relates to gas holder maintenance. PG&E's position is that the maintenance work is necessary. The work was delayed until the completion of the 1981 Transient Bay Area Holder Study and the decision which followed as to which gas holders to retain. According to PG&E, it would not have been prudent to perform maintenance on these facilities realizing that the Study was nearing completion and not knowing which gas holders would remain in service. The Study pointed out that six of the ten existing gas holders could be retired. The staff witness contended that this is deferred maintenance, yet he agreed that delaying maintenance on the gas holders until the completion of the 1981 Transient Bay Area Holder Study was prudent on the utility's part.

We conclude that this is not deferred maintenance in the sense we discussed previously. The work was not deferred to improve the utility's financial position. We do not intend to push utilities to spend earmarked maintenance dollars simply to avoid risk of disallowance in a future proceeding. Because we hold the utility accountable to provide safe, reliable and efficient service, the utility should be able to move maintenance dollars from one account to another for the reasons provided in this case. We will not adopt the staff adjustment.

<u>Account 843.7 Maintenance of Compressor Equipment</u>

PG&E requested $713,000; the staff recommends $79,000, leaving $634,000 at issue. The difference relates to maintenance on compressors for gas holders.

For the reasons set forth in our discussion of Account 843.3, we will not adopt the staff adjustment.

The following table sets forth the adopted Gas Department Storage Expenses.

Gas Department

STORAGE EXPENSES

Test Year 1984

(000's Omitted)

Account No.	Description	PG&E	Staff	Adopted
	OPERATION			
	Underground Storage Expense			
814	Operation Supervision and Engineering	$ 92	$ 92	$ 92
816	Wells Expenses	90	90	90
817	Lines Expenses	26	26	26
818	Compressor Station Expenses	322	267	322
819	Compressor Station Fuel and Power	3,693	3,370	3,422
820	Measuring and Regulating Station Expenses	266	205	266
821	Purification Expenses	126	126	126
823	Gas Losses	923	0	0
824	Other Expenses	332	332	332
825	Storage Well Royalties	174	163	174
840	Operation Supervision and Engineering	61	61	61
841	Operation Labor and Expenses	432	432	432
842.10	Fuel	0	0	0
842.20	Power	207	135	207
	Total Storage Operation Expenses	$6,744	$5,299	$5,550
	MAINTENANCE			
	Underground Storage Expense			
830	Supervision and Engineering	$ 27	$ 27	$ 27
831	Structures and Improvements	116	116	116
832	Reservoirs and Wells	202	172	202
833	Lines	60	14	60
834	Compressor Station Equipment	205	101	101
835	Measuring and Regulating Station Equipment	264	255	264
836	Purification Equipment	92	69	92
837	Other Equipment	619	614	619
	Local Storage Expense			
843.10	Supervision and Engineering	51	46	51
843.20	Structures and Improvements	74	73	74
843.30	Gas Holders	372	292	372
843.90	Other Equipment	45	45	45
843.70	Maintenance of Compressor Equipment	713	79	713
	Total Storage Maintenance Expenses	$2,840	$1,903	$2,736
	Total Storage Expenses (1981 Dollars)	$9,584	$7,202	$8,286
	Escalation Amounts			
	Labor	780	492	766
	Non-Labor	462	192	211
	Total (1984 Dollars)	$10,826	$7,886	$9,263

4. Transmission Expenses

In 1981 dollars, PG&E's estimate of total Transmission Expenses of $22,598,000 exceeds the staff's estimate of $19,947,000 by $2,651,000. The reasons for this difference are:

Pipeline Operations Staffing Levels	$ 409,000
Estimating Techniques	31,000
Deferred Maintenance	1,831,000
River Crossing Survey	163,000
Right-of-Way Clearance	125,000
Clean Pipelines	92,000
Total	$2,651,000

The first three differences are common to many accounts in this functional group and are discussed prior to the account-by-account analysis.

a. Pipeline Staffing Levels

PG&E points out that in its 1982 Test Year General Rate D.93887 (p. 107), the Commission agreed with PG&E that the utility would need to increase its pipeline operations staffing for Line 300 in order to take full advantage of the less expensive gas supplies available from El Paso Natural Gas Company (El Paso).

PG&E notes that its estimates in this proceeding were based on 1981 recorded data. However, because base year 1981 recorded costs do not reflect these new positions, PG&E added costs associated with 27 of the 43 previously authorized positions to the 1981 base figures. PG&E notes that due to reorganization efforts and productivity improvements, PG&E requires only 27 of the 43 positions previously authorized. PG&E submits that cost estimates for pipeline operations personnel, which appear in both the storage and transmission areas, reflect these cost savings. Staff recommends disallowance of several of the 27 positions. In the Transmission expense area the disallowance of pipeline operations staffing amounts to $409,000.

We are not convinced by PG&E's argument that more personnel are required to operate Line 300 simply because of increased flows. There may be valid reasons for adding a few new personnel, but certainly there is little justification for the large manpower increase sought by PG&E. We will review this issue on an account-by-account basis.

b. Estimating Technique

As in the Production Expense area, PG&E relied on 1981 recorded data as the base to which adjustments were applied. Staff used trends of 1976-81 data.

We will review this issue on an account-by-account basis.

c. Deferred Maintenance

In the Transmission Expense area, the difference between utility and staff relating to deferred maintenance is $1,831,000. As discussed previously, we will not provide PG&E with funding for deferred maintenance.

d. Review of Specific Accounts

We will review the accounts where there is a difference between PG&E and staff. We will not discuss accounts where the only difference is escalation rates or deferred maintenance. The adopted escalation rates and disallowance of deferred maintenance will be reflected in the adopted summary of earnings.

Account 850 Supervision and Engineering

PG&E requested $2,918,000; the staff recommends $2,882,000, leaving $36,000 at issue. This difference is caused by the pipeline operations staffing level dispute, discussed above.

According to PG&E, the requested staffing level in this account is required to monitor transmission pipeline encroachments, as well as to supervise maintenance and operations activities on Line 300 and Line 400.

The staff witness allowed 3 of the 4 pipeline operations positions found reasonable in the last general rate case decision.

The staff position is reasonable. We will adopt the staff adjustment.

Account 853 Compressor Station Labor and Expenses

PG&E requested $2,973,000, the staff recommends $2,836,000, leaving $137,000 at issue. The only difference between utility and staff estimates is pipeline operations staffing levels at the new Gerber Cogeneration Plant, amounting to $137,000. The staff witness agreed that his estimate was the 1981 recorded figure. PG&E argues that the 1981 figure does not include the Gerber Cogeneration Plant personnel requirements because that plant did not become operational until October 1982.

We will adopt PG&E's estimate.

Account 856 Mains Expense

PG&E requested $2,585,000; the staff recommends $2,179,000, leaving $406,000 at issue.

In this account, PG&E made four adjustments to the 1981 recorded base level of expenses totaling $761,000. The staff recommends allowance of $355,000 of the total adjustment, the remainder being the $406,000 at issue.

The first adjustment was for pipeline operations personnel. We are not convinced by PG&E's argument that because of increased flow more personnel are needed to operate the transmission lines. We will adopt the staff adjustment for personnel.

The second of these adjustments relates to river crossing studies. In its NOI, PG&E requested $137,000. In its application, this amount was increased by $163,000 to a total of $300,000. The $163,000 was to fund a 10-year review of PG&E's major river crossings to ensure that the pipelines are where they are supposed to be and safe. The original $137,000 is for a specific survey of the Stockton Ship Channel crossing being performed at the behest of the Army Corps of Engineers.

Staff accepted the $137,000 estimate but recommends disallowance of the additional $163,000 since the utility has not provided sufficient justification for a systemwide expansion of the program.

We will adopt the staff recommended adjustment.

The third adjustment is for right-of-way clearing of the existing Line 400, which is the major pipeline that brings gas from Canada. PG&E explained that the utility had not cleared the Line 400 right-of-way for several years under the assumption that it could be cleared at the same time the parallel Western Leg of the Alaska Natural Gas Transportation (ANGTS) system was installed. Now that the ANGTS project has been delayed for several years, PG&E argues it must clear the Line 400 right-of-way. This adjustment totals $100,000. Two other minor right-of-way clearance projects make up the remaining $25,000.

The staff submits that continued normal levels of right-of-way clearance over this period of time would have resulted in a far smaller burden of work to be done at this time. According to staff, the delay while waiting for the ANGTS project to commence has undoubtedly increased the amount of work which needs to be done.

We conclude that it was reasonable for PG&E not to expend funds for the reason set forth above. We will not push utilities into spending ratepayer money simply to avoid disallowance in future proceedings. We will adopt PG&E's estimate for right-of-way clearing.

A fourth adjustment, in the amount of $92,000, is for cleaning Lines 57A and 57B that connect McDonald Island to the Bay Area. This cleaning is necessary to ensure efficient movement of gas during peak periods from the storage field to the Bay Area.

Staff contends that this work was last done five years ago, and is, therefore, included in embedded cost estimates of that period of time. The methodology of the staff was essentially to remove nonrecurring expenditures in this account other than the $218,000 for additional pipeline operations personnel and the $137,000 of the initial river crossing surveys. This additional $355,000 of nonrecurring items added to the base level of expenses in this account produces the Commission staff estimate for the account.

We will adopt the staff recommended adjustment of $92,000 for clearing pipelines.

Account 857 Measuring and Regulating Station Expense

PG&E requested $2,251,000; the staff recommends $2,104,000, leaving $147,000 at issue. This dispute relates entirely to the Pipeline Operations staffing level and the Line 300 restoration program discussed previously.

Under the staff's estimating procedure at least one employee will be authorized at both the Willows and Hinkley facilities but the extra individuals who may or may not have been hired at this point at Hinkley and who have not been hired at Willows have been disallowed. Staff argues that in light of the fact that the utility is not up to its full level of staffing and may, in fact, not reach that level during the test year if past practices continue, the increased base level of expenditures is ~~also not justified. The base level of~~ expenditure disallowance and the two employees disallowed represent the difference between the utility and staff estimates.

We will adopt the staff recommended adjustment.

Account 859 Transmission Maps and Records

PG&E requested $239,000; the staff recommends $177,000, leaving $62,000 at issue. The only difference between utility and staff estimates is pipeline operations staffing levels amounting to $62,000.

PG&E states that it requires these positions to update Line 300 station drawings in order to provide accurate records from which to begin reconstruction of portions of the 33-year old facilities.

Staff recommends disallowance 2 of the 3 requested positions.

We agree with PG&E that there is a need to have updated drawings of its facilities, especially for safety and disaster planning situations. We will authorize funding for the 3 positions as requested by PG&E and we will expect staff to verify whether PG&E does follow through with the updating of the drawings and hiring of personnel for this work.

We will not adopt the staff recommended adjustment.

Account 859 Other Expenses

PG&E requested $1,016,000; the staff recommends $989,000, leaving $27,000 at issue. The only difference between utility and staff estimates is pipeline operations staffing levels amounting to $27,000.

Staff would allow only one of the two positions reflected in this account.

We will adopt the staff recommended adjustment.

Account 862 Structures and Improvements

PG&E requested $269,000; the staff recommends $180,000, leaving $89,000 at issue. The difference relates to major repairs on Line 300 structures and buildings. The utility's position is that it has been 33 years since any major repairs have been performed on Line 300 structures and buildings. By performing maintenance on these old buildings, PG&E argues that it will prolong the life of the structures and avoid major capital reconstruction.

The staff witness disallowed $89,000 based on the deferred maitenance argument.

We will not provide PG&E with funding for deferred maintenance. We will adopt the staff adjustment.

Account 863 Mains

PG&E requested $2,224,000; the staff recommends $1,225,000, leaving $999,000.

The utility is seeking $999,000 to lower and recondition gas lines. According to PG&E the major portion of this expense involves reconditioning and lowering of pipelines in the Rio Vista area where erosion and deep plowing are creating an increasing dig-in problem. $151,000 worth of expenditures is necessary to shore-up Line 21 in Ukiah, where the recent severe winters have created mudslides and otherwise threatened the reliability of this line. Similar problems, including both dig-ins related to farming and mudslide damage, are occurring on Line 300 near Kettleman.

PG&E argues that these projects are part of a continuing and expanding effort to lower and recondition certain vulnerable sections of pipeline. PG&E notes that in 1983, the utility lists over $760,000 of activities above the 1981 base year level in this area. According to PG&E, this is not a situation of the utility not doing funded work, but rather a question of increasing work requirements, only a portion of which can be done each year.

We will provide the funding requested by PG&E for lowering and reconditioning pipelines because of the safety considerations. The amount provided is considerably more than a typical test year level of expenditure. We expect staff to follow up on this item in PG&E's next general rate case. We will adopt PG&E's estimate.

Account 864 Compressor Station Equipment

PG&E requested $4,022,000; the staff recommends $3,318,000, leaving $704,000 at issue. PG&E contends that these dollars are directly related to a reduction in the time interval between major overhauls on compressors from 40,000 to 30,000 hours. PG&E argues that with increasing El Paso flow rates and the need for higher reliability, the utility must maintain the compressors on Line 300 at a higher level. According to PG&E, this program is another aspect of the Line 300 restoration work.

The staff recommends disallowance of these funds on the basis that this is deferred maintenance. Staff notes that for the Line 300 compressors, the utility is proposing to change the overhaul maintenance interval from 40,000 to 30,000 hours of operation. The manufacturers-recommended overhaul interval period is only 20,000 hours. Yet the utility has been operating these units at 40,000-hour overhaul intervals for many, many years.

We agree with staff that the change in flow rates is hardly a basis for a change in maintenance schedule. However, we note that these units have been in operation for many years. The age of these units is a factor which should be considered. We conclude that this is a management decision, because we hold PG&E accountable if it becomes necessary to cut-back El Paso deliveries for lack of compressor availability and consequently PG&E has to take other more expensive supplies of gas to replace El Paso gas.

We conclude that this is not deferred maintenance in the sense discussed previously. We will adopt PG&E's estimate.

Account 865 Measuring and Regulating Station Equipment

PG&E requested $782,000; the staff recommends $738,000, leaving $44,000 at issue. This difference is related to dehydrator maintenance. The utility's position is that this work is now scheduled to be performed in 1984 since it was unable to do this work before due to higher priority maitenance work.

The staff's position is that this is unrecoverable deferred maintenance work; but at the same time, the staff witness agreed that this maintenance work is necessary.

We will adopt the staff adjustment.

The adopted expenditures for Transmission Expense are shown on the following table.

Gas Department

TRANSMISSION EXPENSES

Test Year 1984

(000's Omitted)

Account No.	Description	PG&E	Staff	Adopted
	OPERATION			
850	Supervision and Engineering	$ 2,918	$ 2,882	$ 2,882
851	System Control and Load Dispatching	1,328	1,328	1,328
853	Compressor Station Labor and Expenses	2,973	2,836	2,973
854	Gas for Compressor Station Fuel	0	0	0
855	Other Fuel and Power for Compressor Stations	159	159	159
856	Mains Expenses	2,585	2,179	2,304
856	Removal of Condensate	(219)	(219)	(219)
857	Measuring and Regulating Station Expenses	2,251	2,104	2,104
858	Transmission and Compression of Gas by Others	236	236	236
859	Transmission Maps and Records	239	177	239
859	Other Expenses	1,016	989	989
860	Rents	92	92	92
859	Joint Expenses	1,036	1,036	1,036
	Total Transmission Operation Expenses	$14,614	$13,799	$14,123
	MAINTENANCE			
861	Supervision and Engineering	$ 683	$ 683	$ 683
862	Structures and Improvements	269	180	180
863	Mains	2,224	1,225	2,224
864	Compressor Station Equipment	4,022	3,318	4,022
865	Measuring and Regulating Station Equipment	782	738	738
867	Other Equipment	4	4	4
	Total Transmission Maintenance Expenses	$ 7,984	$ 6,148	$ 7,851
	Total Transmission Expenses (1981 Dollars)	$22,598	$19,947	$21,974
	Escalation Amounts			
	Labor	3,598	3,278	3,507
	Non-Labor	1,387	718	934
	Total (1984 Dollars)	$27,583	$23,943	$26,415

5. <u>Distribution Expenses</u>

PG&E estimates its total Gas Department Distribution Expenses will be $77,631,000; the staff estimates $75,173,000. The disputed amount of $2,458,000 exists due to the following differences:

Service Staff	$ 215,000
Estimating Technique	653,000
Deferred Maintenance	357,000
Productivity Analysts	196,000
Scheduled Meter Changes	69,000
MIDAs	378,000
Fremont Meter Plant Employees	90,000
K-Regulator Program	500,000
Total	$2,458,000

Servicemen, Estimating Technique, and Deferred Maintenance are generic issues which will be take up prior to the account-by-account discussion.

a. <u>Service Staff</u>

PG&E included ten additional gas service positions for the test year to reflect customer growth. According to PG&E this increase equates to a 1.1% increase in staff in comparison to an anticipated customer growth of 3.2% by 1984. Increases in service positions are normally proportional to increases in customer growth. Thus, PG&E argues, these estimated increases are conservative.

Gas service staff costs are expensed under the following accounts: Account 874, Account 878, Account 879, Account 893, and Account 893. In 1981 there were 922 authorized gas service positions systemwide. In 1980, all 922 were filled. According to PG&E, in 1981, the base year, service staff levels were reduced to 887 filled positions commensurate with a declining workload allegedly due to the depressed economy.

In estimating gas service staff requirements for the test period, PG&E made adjustments to the 1981 base to bring it up to the number of positions that would be required under "normal" economic conditions. In addition, PG&E determined that a customer-to-service staff ratio of 3200-to-1 is appropriate, and therefore, added 10 additional positions to reflect customer growth during 1982-1984. Thus, PG&E has requested funding for 932 gas service positions.

PG&E points out that staff was not consistent in estimating gas service staff requirements. In Accounts 874 and 893 staff trended the account. In Accounts 878 and 879 staff disallowed 25% of the utility's requested increase. And, in Account 893, staff agreed to the utility's estimate. PG&E argues that this variable treatment of gas service staff costs is illogical, since the costs of a typical service position would be spread over all of these accounts.

We conclude that PG&E's funding request for 932 gas service positions is reasonable.

b. <u>Estimating Technique</u>

A dispute over estimating technique accounts for $753,000 of the difference between PG&E and staff Distribution Expense estimates. As in ~~the Production and Transmission Expense areas~~, PG&E used 1981 recorded data plus appropriate adjustments; staff employed trending analyses.

We will review this issue on an account-by-account basis.

c. <u>Deferred Maintenance</u>

The staff's recommended disallowance of deferred maintenance results in a $357,000 difference. Deferred maintenance was discussed previously.

We will disallow PG&E's request for deferred maintenance funding.

d. <u>Review of Specific Accounts</u>

We will review the differences between PG&E and staff on an account-by-account basis.

<u>Account 870 Supervision and Engineering</u>

PG&E's estimate is $8,542,000; the staff recommends $8,346,000, leaving $196,000 at issue. According to PG&E the

$196,000 represents the cost of 7 existing productivity analysts who administer PG&E's crew productivity programs in the 13 operating divisions.

The PG&E witness testified that the 7 productivity analyst positions do not represent an increase in staff levels but rather a transfer of A&G expenses to an M&O account. The 7 productivity analysts are trainers who are administering the utility's crew productivity efforts for its transmission and distribution employees.

The staff witness agreed that the 7 productivity analysts were already on the job and that their related expenses simply represent an accounting adjustment. According to PG&E, the staff witness failed to include the 7 analysts in his trend, and he has therefore understated his test year estimate.

We will adopt PG&E's estimate.

Account 871 Distribution and Load Dispatching

PG&E requested $494,000; the staff recommends $484,000, leaving $10,000 at issue. The utility's estimate was based on 1981 recorded expenses of $494,000. PG&E argues that this estimate is most representative of current operating conditions, and is actually $9,000 below 1982 recorded expenses.

We will adopt PG&E's estimate.

Account 874 Mains and Services Expenses

PG&E's estimate is $3,135,000; the staff recommends $2,695,000, leaving $440,000 at issue.

The staff estimate is based on a five-year trend. PG&E contends the staff approach fails to account for two major changes in operating conditions. PG&E notes that its estimate builds upon a 1981 recorded base level of activity, then adds adjustments for the increased Emergency Zone Valve Maintenance Program and a Pipeline PCB Liquids Removal Program.

The Emergency Zone Valve Maintenance Program was stimulated by the major dig-in incident in downtown San Francisco two years ago. As a result of that incident, the utility determined that the valve maintenance frequency should be increased from once-a-year to twice-a-year.

The PCB program is an ongoing effort on the part of the utility to identify and to drain its gas distribution system of any PCB contaminants.

We will adopt PG&E's estimate.

Account 878 Removing and Resetting Meters and Regulators

PG&E's estimate is $13,138,000; the staff recommends $12,950,000, leaving $188,000 at issue.

The utility's request provides for a 1980 service staffing level of 922 positions plus 10 additional positions in 1984 to reflect normal conditions and the growth in customers since 1980. The PG&E witness testified that the requested customer to service positions ratio for 1984 of 3200-to-1 is as high or higher than any of the preceding normal years, indicative of productivity gains. PG&E is assuming 1984 will be a "normal" year with an improved economy and resultant increased customer activity (e.g., turn-ons, turn-offs, change of parties, new meter sets). Also, PG&E has included upward adjustments for tamperproofing of meters to ensure against theft of gas.

The staff witness disallowed $107,000 of the utility's $428,000 request for an increase in the level of service staff. This recommended disallowance constitutes a 25% reduction in the request.

As discussed previously, we conclude that PG&E's funding request for 932 service positions is reasonable. Therefore we will adopt PG&E's estimate.

Account 878 Miscellaneous Meter Changes

PG&E has requested $510,000; the staff recommends $436,000, leaving $74,000 at issue. Staff and PG&E disagree on the clerical requirements at the Fremont Meter Repair facility. PG&E's estimate includes $74,000 for clerical positions to administer the revised, more sophisticated meter history program located at the meter shop. Of this figure, $37,000 is for two positions that formerly were charged to Account 880 and are now charged to this Account 878. The remaining $37,000 is for two positions that were filled in late 1981 and, therefore, not totally included in the utility's 1981 base information.

Staff's disallowance is based on the assertion that increased productivity should offset the costs associated with the increased clerical personnel requirements. We will adopt PG&E's estimate.

Account 880 Distribution Maps and Records

PG&E has requested $4,005,000; staff recommends $3,627,000, leaving $378,000 at issue. The issue involves savings associated with the implementation of MIDAS in the Peninsula District and its expansion throughout San Jose Division in 1984 and 1985. As the MIDAS question has been reviewed in the Electric Distribution Expenses portion of this opinion, the arguments will not be repeated here.

We are not convinced that the staff's estimate of savings will be achieved in the test year. We will adopt PG&E's estimate.

Account 879 Customer Installation Expenses - General

PG&E requested $12,451,000; the staff recommends $12,343,000, leaving $108,000 at issue. The reason for the difference is the staff recommended disallowance of 25% of the requested increase in service positions.

As discussed previously, we adopt PG&E funding request for 932 service positions for the test year. Accordingly we will adopt PG&E's estimate.

Account 885 Supervision and Engineering

PG&E requested $3,591,000; the staff recommends $3,501,000, leaving $90,000 at issue.

PG&E has requested funding for three existing industrial engineers and an assistant at the Fremont Meter Repair facility. PG&E notes that three of the four positions are filled at the Fremont Meter Repair facility. These engineers had been added to the work force subsequent to the last general rate case, hence in estimating test year expenses, PG&E argues that their positions should be treated as a special adjustment to the 1981 base figure.

We will adopt the PG&E estimate.

Account 886 Structures and Improvements

PG&E requested $6,000; the staff recommends $4,000, leaving $2,000 at issue. The utility's estimate was based on 1981 record expense plus modifications for specific programs. The staff provided no increase over 1981 recorded expenditures. Some growth is reasonable. We will adopt PG&E's estimate.

Account 887 Mains - Leak Clamps

PG&E requested $934,000; the staff recommends $834,000, leaving $100,000 at issue. The Avon Seal Program, which involves surveying and sealing of joints in the old cast iron distribution system in downtown Sacramento, accounts for $91,000 of this difference.

The second area of diagreement is $9,000 for the cast iron pipe repair program in the Stockton Division.

Staff agrees that the work is necessary but recommends disallowance because it is deferred maintenance.

We will adopt the staff adjustment.

Account 887 Mains - Other

PG&E requested $8,472,000; the staff recommends $8,315,000, leaving $157,000 at issue. The major area of disagreement is whether $120,000 for pressure uprates constitutes unrecoverable deferred maintenance. PG&E argues that it delayed until 1984 performing certain distribution system pressure uprate work because load growth did not materialize at the level originally expected, due to the depressed economy, thus removing the justification for performing that work in 1981. PG&E contends that without the increased load, it did not make sense to spend the dollars to upgrade the carrying capacity of the pipe. According to PG&E this decision to defer the pressure uprate work until 1984 was based on prudent engineering judgment.

The staff agreed that it was prudent to defer this expenditure.

We do not consider this to be deferred maintenance in the sense discussed previously. We do not intend to push utilities into spending ratepayer money where it is not needed. Therefore we will not adopt the staff recommended adjustment.

The second area of disagreement is $37,000 for cathodic protection. According to PG&E these dollars involve an increase in the level of program activity in order to eventually achieve 100% cathodic protection of the utility's distribution system. Staff recommends disallowance of these funds as deferred maintenance.

We will adopt the staff recommended adjustment related to deferred maintenance on cathodic protection.

Account 889 Measuring and Regulating Station
Station Equipment - General

PG&E requested $1,030,000; the staff recommends $941,000, leaving $89,000 at issue. The areas of difference are $61,000 for sealing and upgrading vaults, and $28,000 for a control mechanic. According to PG&E, the vault maintenance was delayed due to higher priority work. The adjustment for the control mechanic is for an existing mechanic's position that was not included in the utility's 1981 recorded base level.

The staff argues that all $89,000 is deferred maintenance.

We will adopt the staff recommended adjustment for deferred maintenance on vaults.

We will not adopt the staff recommended adjustment for the mechanic.

Account 890 Measuring and Regulating
Station Equipment - Industrial

PG&E requested $334,000; the staff recommends $298,000, which leaves a $36,000 estimating technique difference at issue. The utility made an adjustment to the 1981 recorded level to reflect increased maintenance on industrial meter and regulator sets. According to PG&E, the utility has been experiencing problems with defective chart drives that need to be rectified. PG&E argues that the staff trended estimate does not reflect this increased maintenance need.

We will adopt PG&E's estimate.

Account 892 Services

PG&E requested $4,643,000; the staff recommends $4,553,000, leaving an estimating technique difference of $90,000. According to PG&E the utility included an adjustment for an increase in its program to achieve 100% cathodic protection of its distribution system. This is the same program discussed in Account 887, Mains - Other, for which the expenses are divided and recorded in two accounts.

The staff's position is that the historical trend should be used. Staff does support the cathodic protection program, and endorses the utility's goal to obtain 100% cathodic protection.

Staff argues that $11,000 relates to deferred maintenance involving cathodic protection in the Sacramento area. Staff further argues that the utility has not explained a $110,000 increase in maintenance activities.

We will adopt the staff recommended adjustment to this account.

Account 893 Meters

PG&E requested $4,256,000; the staff recommends $3,756,000, leaving $500,000 at issue. The utility reduced its original estimate by $500,000 for reduced scheduled meter charges, and at the same time increased the original estimate by $500,000 for the K-Regulatory Safety Program.

The staff based its estimate on a trend. The staff witness agreed that PG&E should perform the inspection program on the K-Regulator.

We agree with staff that it is a surprising coincidence that the cost of the K-Regulator Program equals the reduction made by PG&E. At the same time we bear in mind that the K-Regulator Program is a safety related program and should be implemented without delay. Since the cost of the K-Regulator Program is not recognized by the staff trend, we will authorize the full amount requested by PG&E.

We require a report from PG&E in the next general rate case proceeding on the K-Regulator Program.

The adopted expenditures for Distribution Expense are set forth on the following table.

Gas Department

Distribution Expense

Test Year 1984

(000's Omitted)

Account No.	Description	PGandE	Staff	Adopted
	Operation			
870	Supervision and Engineering	$ 8,542	$ 8,346	$ 8,542
871	Distribution Load Dispatching	494	484	494
874	Mains and Services Expenses	3,135	2,695	3,135
875	Measuring and Regulating Station Expenses - General	1,236	1,236	1,236
876	Measuring and Regulating Station Expense - Industrial	336	336	336
878	Removing and Resetting Meters and Regulators	13,138	12,950	13,138
878	Miscellaneous Meter Expenses	510	436	510
880	Distribution Maps and Records	4,005	3,627	4,005
880	Other Expenses	9,924	9,924	9,924
881	Rents	58	58	58
879	Customer Installation Expenses - General	12,451	12,343	12,451
	Total Distribution Operation Expenses	$53,829	$52,435	$53,829
	Maintenance			
885	Supervision and Engineering	$ 3,591	$ 3,501	$ 3,591
886	Structures and Improvements	6	4	6
887	Mains - Leak Clamps	934	834	834
887	Mains - Other	8,472	8,315	8,435
888	Compressor Station Equipment	2	2	2
889	Measuring and Regulating Station Equipment - General	1,030	941	969
890	Measuring and Regulating Station Equipment - Industrial	334	298	334
892	Services	4,643	4,553	4,553
893	Meters	4,256	3,756	4,256
893	House Regulators	339	339	339
894	Other Equipment	195	195	195
	Total Distribution Maintenance Expenses	$23,802	$22,738	$23,514
	Total Distribution Expenses (1981 Dollars)	$77,631	$75,173	$77,343
	Escalation Amounts			
	Labor	14,556	14,364	14,515
	Non-Labor	3,365	1,913	2,324
	Total (1984 Dollars)	$95,552	$91,450	$94,182

6. Customer Accounts Expense

Estimates of the Electric Department and Gas Department Customer Accounts Expenses are derived from an allocation of total expenses. This is done because the expenses are similar or identical for both departments since, for the most part, it is the same meter reader or the same clerk performing work for both departments. Therefore, issues which were discussed in the Electric Department Customer Accounts section are also common to the Gas Department and will not be repeated.

The reasons for the difference between PG&E and staff are the following:

Estimating Technique	$ 806,000
Customer Awareness	1,287,000
Manual Meter-Reading Subtraction	426,800
Postage Rates	780,800
Total	$3,299,000

We will discuss the differences on an account-by-account basis.

a. Review of Specific Accounts

Account 901 Supervision

PG&E requested $2,618,000, the staff recommends $2,624,000, leaving $6,000 at issue. Estimating techniques cause this difference. We conclude that PG&E's estimate is more reasonable. We will adopt PG&E's estimate.

Account 902 Meter
Reading Expenses

PG&E requested $10,237,000; the staff recommends $9,565,000, leaving $672,000 at issue. The primary difference between utility and staff estimates is the staff's disallowance of $426,000 for manual meter reading subtraction. This issue is discussed in the Electric Department Account 902. We might repeat that we do not expect to see the cost of manual meter reading subtraction expense in PG&E's next general rate case.

We will adopt half the staff adjustment related to manual meter reading subtraction because we expect this item to be phased out by the time of PG&E's next general rate case proceeding.

A second issue is the Customer Awareness Program, which involves a $207,000 difference for the Reading Your Own Meter Program. As discussed previously in electric department expenses, we will allow a portion of PG&E's request.

The final difference between PG&E and staff estimate is due to the use of different estimating techniques. $39,000 is at issue. We will adopt PG&E's estimate.

Account 903 Customer
Contracts and Orders

PG&E requested $12,557,000; the staff recommends $11,371,000, leaving a difference of $1,186,000. The primary difference is staff's disallowance of Customer Awareness Program expenses, amounting to $930,000. This amount is composed of the following programs: High Bills - $716,000; Plan Your PGandE Bill - $179,000; Safty Communications -- $21,000; and Community Meetings -- $14,000.

The Customer Awareness programs were discussed previously for Electric Department Account 903. We will reflect the same adjustments.

The remaining issue, which involves a difference of $256,000, involves the use of different estimating techniques. We conclude that PG&E's estimate is reasonable.

Account 903 Customer Billing and Accounting

PG&E requested $7,588,000; the staff recommends $7,138,000, leaving a difference of $450,000. Two issues cause this difference. The staff's disallowance of Customer Awareness Program expenses accounts for $136,000 of the difference ($130,000 -- Balanced Payment Plan; $6,000 -- Lifeline Changes). As discussed in Electric Department expenses, we will reflect the same adjustments for these programs.

The remainder, $314,000, is due to the use of different estimating techniques. We will adopt staff's estimate.

Account 903 Mailing Customers' Bills

PG&E requested $5,003,000; the staff recommends $4,304,000, leaving a difference of $699,000. This difference occurs because PG&E's witness assumed postage rates to be 23 cents for first-class mail in 1984. The staff, in contrast, assumed no increase in postage costs.

We will reflect the same ratemaking treatment adopted in Electric Department Account 903.

Account 903
Collecting Expenses

PG&E requested $12,178,000; the staff recommends $12,178,000, leaving a coincidental difference of $0 due to the allocation of expenses between the Electric and Gas Departments. One difference between utility and staff estimates is the use of different estimating techniques. This amounts to a negative $95,000.

A second issue dividing utility and staff is the Customer Awareness Program Expenses, which involves a $14,000 difference between the parties. $5,000 is for the Pay Station Program and $9,000 is for third-party notification requirements.

The final difference between utility and staff estimates is $81,000. This difference occurs because the staff does not anticipate there will be a first-class postage rate increase in 1984.

All three of these issues are reviewed extensively in preceding Electric Department sections. We will adopt the same treatment of issues for the gas department.

Account 904
Uncollectible Accounts

PG&E and staff agree on a .251% uncollectible factor. We will reflect this factor in the adopted expense for this account.

Account 905 Miscellaneous
Customer Accounts Expenses

PG&E requested $4,508,000; the staff recommends $4,210,000, leaving a difference of $298,000. The cause of this difference is the use of different estimating techniques. We will adopt staff's estimate.

Account 905 Rents

PG&E stipulated to the staff's estimate of $181,000. The adopted Gas Department Customer Accounts Expenses are shown on the following table.

Gas Department

CUSTOMER ACCOUNTS EXPENSES

Test Year 1984

(000's Omitted)

Account No.	Description	PGandE	Staff	Adopted
901	Supervision	$ 2,618	$ 2,624	$ 2,618
902	Meter Reading Expenses	10,237	9,565	9,838
903	Customer Contracts and Orders	12,557	11,371	11,865
903	Customer Billing and Accounting	7,588	7,138	7,209
903	Mailing Customers' Bills	5,003	4,304	4,304
903	Collecting Expenses	12,178	12,178	12,097
905	Miscellaneous Customer Accounts Expenses	4,508	4,210	4,210
905	Rents	181	181	181
	Total Excluding Uncollectible Accounts	$54,870	$51,571	$52,322
904	Uncollectible Accounts	1,309	1,309	1,309
	Total Including Uncolletible Accounts (1981 Dollars)	$56,179	$52,880	$53,631
	Escalation Acounts			
	Labor	9,974	9,815	9,853
	Non-Labor	1,739	886	1,062
	Total (1984 Dollars)	$67,892	$63,581	$64,546

7. Customer Services Expense

This section covers the expenses for Conservation and Load Management discussed previously.

The adopted expenditures are set forth in the following tables.

Gas Department

CUSTOMER SERVICE AND INFORMATION EXPENSES

Test Year 1984

(Excluding Load Management)

(000's Omitted)

Account No.	Description	PGandE	Staff	Adopted
907	Supervision	$ 2,147	$ 2,144	$ 2,144
908	Customer Assistance Expense	7,613	8,514	7,826
909	Informational and Instructional Advertising Expenses	916	553	553
910	Miscellaneous Customer Service and Information Expenses	1,612	1,630	1,630
	Total Customer Service & Information Expense (1981 Dollars)	$12,288	$12,841	$12,153
	Escalation Amounts			
	Labor	1,420	1,437	1,437
	Non-Labor	1,096	728	739
	Total (1984 Dollars)	$14,804	$15,006	$14,329

Gas Department

CUSTOMER SERVICE AND INFORMATION EXPENSES
(EXCLUDING LOAD MANAGEMENT)

EXPENSES BY PROGRAM

Test Year 1984

(000's Omitted)

Program	PG&E	Staff	Adopted
CONSERVATION			
Appliance Efficiency	$ 1,092	$ 1,092	$ 1,092
Master Meter Conversion	1,063	1,063	375
Energy Management	5,831	5,169	5,831
Agricultural Energy Management	89	89	89
Energy Management Incentives	1,028	2,500	1,838
Technical Support & Demonstration	307	307	307
Communications & Seminars	620	196	196
General Customer Inquiries	687	756	756
Program Evaluation	212	310	310
Total Conservation	$10,929	$11,482	$10,794
MARKETING SERVICES	1,359	1,359	1,359
Total (1981 Dollars)	$12,288	$12,841	$12,153

Gas Department

LOAD MANAGEMENT OPERATING EXPENSES

Test Year 1984

Constant 1981 Dollars

(000's Omitted)

Account No.	Description	PGandE	Staff	Adopted
907	Supervision	$ 52	$ 23	$ 11
908	Customer Assistance Expense	1,876	1,274	335
910	Miscellaneous Customer Service and Information Expenses	20	0	4
	Total Load Management Expenses (1981 Dollars)	$1,948	$1,297	$ 350
	Escalation Amounts			
	Labor	216	141	39
	Non-Labor	179	75	22
	Total (1984 Dollars)	$2,343	$1,513	$ 411

8. A&G Expenses

In 1981 dollars, PG&E's estimate of total Gas Department A&G expenses of $147,555,000 exceeds the staff's estimate of $120,760,000 by $26,795,000. With the exception of Property Insurance and Premiums (Account 924) and Pensions and Benefits (Account 926), which were in 1984 dollars, all differences are in 1981 dollars. The reasons for this total difference are:

Effort Study (Account 922)	$ 6,583,000
Estimating Methodology (Accounts 920, 921, 922)	9,201,000
Property Insurance Premiums	52,000
Research, Development, and Demonstration (Account 930.2)	244,000
Feasibility Studies (Account 930.2)	3,048,000
AGA (Account 930.2)	267,000
Industry Association Dues (Account 930.2)	32,000
EEO (Account 930.2)	62,000
Rents (Account 931)	248,000
Facilities Development Estimate (Account 923)	84,000
Pension and Benefits	7,142,000
Total	$26,795,000

A&G expenses are allocated between the Electric and Gas Departments. Consequently, the analysis and argument underlying the treatment of Gas Department A&G expenses is the same as set forth in the Electric Department portion of this opinion. It will not be repeated here. The adopted expenditures are set forth on the following table.

Gas Department

ADMINISTRATIVE AND GENERAL EXPENSES

Test Year 1984

(000's Omitted)

Account No.	Description	PGandE	Staff	Adopted
920	Administrative and General Salaries	$ 42,975	$ 37,748	$ 38,043
921	Office Supplies and Expenses	22,608	16,722	17,513
922	A&G Expenses Transferred - Credit	(11,281)	(15,952)	(13,889)
923	Outside Services	2,167	2,251	2,251
924	Property Insurance	317	265	317
925	Injuries and Damages	9,099	9,099	9,049
926	Employee Pensions and Benefits	64,509	57,883	58,233
928	Regulatory Commission Expenses	135	135	135
930.20	Miscellaneous General Expenses			
	Research, Development and Demonstration	3,172	2,928	3,499
	Feasibility Studies	3,048	0	0
	Other Miscellaneous General Expenses	3,674	3,313	3,564
	Total Miscellaneous Gen. Expenses (Acct. 930.2)	9,894	6,241	7,063
931	Rents	1,487	1,239	1,338
932	Maintenance of General Plant	665	665	66[illegible]
	Total Administrative and General Expenses Excluding Franchises (Acct. 927)	$142,575	$116,296	$120,718
927	Franchise Requirements	5,392	4,860	4,860
	Total Including Franchises (Acct. 927) (1981 Dollars)	$147,967	$121,156	$125,578
	Escalation Amounts			
	Labor	10,026	7,515	7,818
	Non-Labor	4,570	1,876	2,225
	Wage Related A&G	87	8	55
	Total (1984 Dollars)	$162,650	$130,555	$135,676

9. Taxes

These issues, common to both departments, have previously been reviewed in the Electric Results of Operations portion of this opinion. The following tables set forth the adopted taxes.

Gas Department

PROPERTY TAX EXPENSES

Test Year 1984

(000's Omitted)

Description	PGandE	Staff	Adopted
Property Tax Expense	$15,322	$15,219	$15,219
Total	$15,322	$15,219	$15,219

Gas Department
PAYROLL TAXES
Test Year 1984
(000's Omitted)

Description	PG&E	Staff	Adopted
FICA	$13,410	$12,499	$12,653
FUI	427	398	408
SUI	897	836	856
S.F. Employee Tax	830	774	793
Total (1981 Dollars)	$15,564	$14,507	$14,710
Escalation Amounts			
Labor	2,799	2,610	2,647
Total (1984 Dollars)	$18,363	$17,117	$17,357

Gas Department

COMPUTATION OF INCOME TAXES

1984 - Present Rates

(000's Omitted)

Description	PG&E	Staff	Adopted
Operating Revenues	$822,073	$822,073	$822,073
O&M Expenses	434,704	384,435	395,461
Taxes Other Than Income	30,886	29,726	29,929
Subtotal	356,483	407,912	396,683
Deductions from Taxable Income			
Operating Expense Adjustments	(7,031)	0	0
Interest Charges	77,417	76,349	77,040
Capitalized Pensions & Benefits	17,454	15,831	15,979
Capitalized Ad Valorem Taxes	92	92	92
Use Taxes	292	292	292
Fiscal/Calendar Adj.	250	147	147
Subtotal Deductions	88,474	92,711	93,550
CCFT Taxes			
CCFT Depreciation	70,759	70,043	70,484
Repair Allowance	1,300	2,235	1,768
Removal Costs	3,013	3,013	3,013
Subtotal Deductions	163,546	168,002	168,815
Taxable Income for CCFT	192,937	239,910	227,868
CCFT	18,522	23,031	21,875
State Tax Adjustment	23	23	23
Current CCFT	18,545	23,054	21,898
Defense Facilities Credit	(3)	(3)	(3)
Deferred Taxes (CCFT)	(602)	0	0
Total CCFT	$17,940	$23,051	$ 21,895
Federal Taxes			
Current CCFT	18,545	23,054	21,898
Federal Tax Depreciation	58,221	58,070	58,163
Preferred Divid. Credit	512	512	512
Subtotal Deductions	165,752	174,347	174,123
Taxable Income for FIT	190,731	233,565	222,560
Federal Income Tax	87,736	107,440	102,378
Graduated Rate Benefit	(7)	(7)	(7)
Defense Facilities Credit	(19)	(19)	(19)
Deferred Taxes (FIT)	(2,606)	0	0
FIT before Adj.	85,104	107,414	102,352
Investment Tax Credit	0	0	0
Total FIT	$85,104	$107,414	$102,352

10. Depreciation Expense

PG&E requested $97,154,000; the staff recommends $97,052,000, leaving a difference of $102,000.

The amount at issue is due to different utility and staff estimates of plant additions for years 1983 and 1984. PG&E and staff agree on the depreciation elements (average service lives, mortality curve types, net salvage rates, and remaining lives) that are used to calculate the depreciation expense for the test year.

The following table sets forth the adopted depreciation expense.

Gas Department

DEPRECIATION EXPENSE

Test Year 1984

(000's Omitted)

Description	PG&E	Staff	Adopted
Gas Department	$90,320	$90,283	$90,250
Common Utility Allocation	6,680	6,615	6,680
StanPac, 6/7 Interest	367	367	367
Changes in Line Extension Rules (Adjustment)	(213)	(213)	-0-
Total	$97,154	$97,052	$97,297

11. Plant and Rate base

The discussion of Gas Plant and Gas Rate Base are combined due to the interrelationship of the two subjects. PG&E's and staff's estimates are set forth below.

	PG&E	Staff	PG&E Exceeds Staff
	(Thousands of Dollars)		
Gas Rate Base with Working Cash	$1,722,670	$1,712,339	$10,291
Working Cash	63,903	63,714	189
Gas Rate Base other than Working Cash	$1,658,727	$1,648,625	$10,102

The items making up the $10,102,000 difference between utility and staff estimates of Gas Rate Base other than working cash are detailed below.

	PG&E	Staff
	(Thousands of Dollars)	
RD&D and Feasibility Studies	$ 6,985	0
Pipeline Repl. Program	1,074	0
Delevan Regenerator Replacement	335	0
Depreciation Reserve	(1,019,694)	(1,019,644)
Computer Capital Allocated to Gas Department	2,369	2,034
Deferred Taxes-ACRS Deducted from Rate Base	(19,714)	(21,289)
Deferred ITC Deducted from Rate Base	(22,887)	(22,735)
Total		

We will discuss these differences.

Gas Department

1984 AMORTIZATION OF FEASIBILITY STUDIES AND RDandD[a/]

($000's Omitted)

Category	PGandE	Staff	Adopted
RDandD			
Ongoing Projects[b/]	$ 315	$ 274	$ 274
Completed Projects[b/]	1,987	1,566	1,566
Feasibility Studies			
Projects in the Long-Term Plan	1,681	0	0
Total Gas Department	$3,983	$1,840	$1,840

a/ Amortization over four-year period.

b/ No AFUDC allowed.

a. RD&D and Feasibility Studies

PG&E's Rate Base estimate includes $6,985,000 of unamortized RD&D and Feasibility Study. The staff estimate includes no allowance for these items. This issue is addressed in the Feasibility Studies and RD&D policy portion of this opinion.

b. Pipeline Replacement Program

PG&E estimates the impact of this program on Gas Department plant at $1,074,000. According to PG&E, capital expenditures under this program are to replace portions of Gas Transmission Pipeline that are approximately 40 years old, and were constructed with what are now outdated materials and welding techniques.

The staff witness contends that a portion of this program work may be completed as Jobs Under $1 Million, and therefore, is already captured in the trending technique used to estimate Jobs Under $1 Million in Gas Rate Base. (Ex. 55, p. 14-6.) Based on this argument, the staff witness has included no allowance for this purpose in the Jobs Over $1 Million category for estimating Gas Rate Base.

PG&E argues that the majority of this work has been done as Jobs Over $1 Million, and that the staff position, if adopted, would result in recovery of an insignificant portion of this program's costs.

We will adopt PG&E's estimate.

c. Replacement Regenerator at Delevan

PG&E included $335,000 in 1984 Gas Plant for this project, while the staff included nothing.

PG&E has been studying two options for the gas compressor station at Delevan: replacing the existing, inefficient regenerator with a new unit or building a cogeneration unit. If the cogeneration unit is built, it would have no impact on test year rate base, due to the necessary extended construction period. The staff witness bases his estimate on the uncertainty over which approach will be taken, and therefore allows no increase in rate base.

We will adopt the staff adjustment.

d. Computer-Related Capital

PG&E's estimate of computer-related capital allocated to the Gas Department is $2,369,000. The staff has included $2,034,000 in its estimate. The difference is $335,000. This item is discussed in the Electric Department portion of this opinion.

e. Deferred Income Taxes and Deferred Investment Tax Credit

The staff estimate for Deferred Income Tax is $1,575,000 higher than PG&E's. The staff estimate of Deferred Investment Tax Credit is $152,000 lower than PG&E's. These differences are due primarily to differences in plant estimates.

The adopted amounts are set forth in the following table.

Gas Department

WEIGHTED AVERAGE RATE BASE
Test Year 1984
(000's Omitted)

Description	PG&E	Staff	Adopted
Weighted Average Gas Plant			
Gas Plant	$2,159,540	$2,158,130	$2,159,258
Gas Plant Held for Future Use	728	728	728
6/7 Interest in STANPAC	21,719	21,719	21,719
Common Plant Allocation	217,281	216,947	216,878
Common Plant Held for Future Use	188	188	188
Total Weighted Average Gas Plant	2,399,456	2,397,712	2,398,771
Working Capital			
Production Fuel	15	15	15
Materials and Supplies	13,692	13,692	13,692
Current Gas Underground	345,334	345,334	345,334
Gas Line Pack	7,000	7,000	7,000
Working Cash	62,885	62,629	62,757
RD&D and Feasibility Studies	6,985	0	0
Total Working Capital	435,911	428,670	428,798
Less Adjustments			
Customer Advances for Construction	49,461	49,461	49,461
Accumulated Deferred Taxes - Defense	129	129	129
Accumulated Deferred Taxes - ACRS	19,714	21,289	22,808
Deferred I.T.C.	22,886	22,734	23,488
Line Extensions	1,871	1,871	0
Total Adjustments	94,061	95,484	95,886
Depreciation Reserve	1,019,694	1,019,644	1,019,677
Total Rate Base	$1,721,612	$1,711,254	$1,712,006

Gas Department

WORKING CASH CAPITAL
DETERMINATION OF WORKING CASH CAPITAL SUPPLIED BY INVESTORS
Test Year 1984
(000's Omitted)

Description	PG&E	Staff	Adopted
Operational Cash Requirement			
Required Bank Balances	$34,740	$34,740	$34,740
Special Deposits and Working Funds	593	593	593
Prepayments	2,608	2,608	2,608
Deferred Debits, Companywide	(9,352)	(9,352)	(9,352)
Subtotal a/	9,472	9,472	9,472
Deferred Debits, Gas Department	160	160	160
Total Operational Cash Requirement	9,632	9,632	9,632
Plus: Working Cash Capital Requirement from Lead Lag Study	77,312	77,056	77,912
Less: Accrued Vacation a/	18,392	18,392	19,121
Total Working Cash Capital Requirement	68,552	68,296	68,423
Less: Working Cash Capital Not Supplied by Investors a/	5,666	5,666	5,666
Working Cash Capital Supplied by Investors	$62,886	$62,630	$62,757

a/ Represents 33.13% allocation to the Gas Department.

f. Working Cash

PG&E requested $63,903,000; the staff recommends $63,714,000, leaving a difference of $189,000. PG&E and the staff agree on the operational cash requirements and on all the expense and revenue lead-lag days. The adopted expense levels, labor, and materials and services escalation rates for 1984 will determine the adopted working cash allowance.

12. Summary of Earnings

The adopted summary of earnings is set forth on the following table.

13. Attrition

The adopted attrition allowance calculation is set forth in the table on page 87.

Pacific Gas and Electric Company
Gas Department

ADOPTED SUMMARY OF EARNINGS
TEST YEAR 1984 AT PRESENT AND AUTHORIZED RATES

(000's Omitted)

	Present Rates	Authorized Rates
Operating Revenues	$ 822,073	$ 900,860
Operating Expenses		
Production	1,436	1,436
Cost of Gas Less Dept. Use	44,398	44,398
Storage	8,286	8,286
Transmission	21,974	21,974
Distribution	77,343	77,343
Customer Account	53,631	53,829
Customer Service & Info.	12,153	12,153
Load Management	350	350
Admin. & General	12,577	126,311
Feas. & RD&D Amortization	1,840	1,840
Subtotal	346,988	347,920
Labor Escalation	40,918	40,918
Non-Labor Escalation	7,555	7,555
Subtotal after Adjustment	395,461	396,393
Book Depreciation	97,297	97,297
Taxes Other Than Income	29,929	29,929
State Corp. Franchise Tax	21,895	29,369
Federal Income Tax	102,352	134,727
Total Operating Expenses	$ 646,934	$ 687,715
Net Operating Revenue	175,139	213,145
Rate Base	1,712,006	1,712,006
Rate of Return	10.23%	12.45%

V. CONSERVATION, LOAD MANAGEMENT, RESEARCH, DEVELOPMENT AND DEMONSTRATION AND COGENERATION

A. Conservation

1. Policy Considerations

Before we can begin a detailed technical discussion of program elements a broadened perspective is required. PG&E properly treats conservation as a preferred resource for its long-term planning. We have discussed and in the main have adopted the staff recommendations regarding resource planning (Ahern, Exhibit 64). The staff testimony is particularly relevant to our conservation deliberations, and is quoted below:

> "1. Conservation - The uncertainty about world oil prices makes cost-effectiveness analysis of conservation programs difficult, if not impossible. Utilities Division staff are using a range of real oil price increases from 0% to 6% a year in order to show which PG&E programs are clearly effective and not effective in providing energy savings worth more than the future cost of energy. Conservation programs are one of the best hedges against increasing energy prices, but, on the other hand, they might result in unneeded investments if prices decline substantially. This uncertainty makes it advisable to maintain PG&E's conservation expenditures at about the currently authorized levels, with cuts of programs that now appear ineffective, after evaluation, and with increases or additions of programs that can help customers who have had limited benefits from existing programs, such as small commercial customers. It is not the time to follow the Energy Commission's recommendations for much accelerated conservation programs, nor is it a time to reject the progress made so far."

PG&E has requested $79.2 million for its 1984 conservation programs which are funded through the rate case, and $88.5 million in 1985 (in 1981 dollars). As staff suggests, these requests must be placed in perspective regarding both prior years' budgets and the total budget, including several programs which are funded separately and thus are not included in the rate case requests. Table 1 shows past authorized and recorded expenditures and PG&E's 1984 requests in current dollars. Substantial increases are requested in both rate case programs and non-rate case programs (RCS, ZIP, and solar).

An important point is that PG&E has not succeeded in matching expenditures with original Commission authorizations, as Table V-1 shows. PG&E carried over $13,371,000 in the unspent 1982 funds to supplement 1983 authorizations, and now plans to spend or encumber the entire 1982-1983 conservation budget by the end of 1983. We note, however, that of this amount, $21,279,000 is projected to be spent between September and December 1983, and another $22,902,000 is expected to be encumbered but not actually spent until 1984. Given the problems which PG&E has exhibited in utilizing the authorized funds, we question whether it could make effective use of the substantial increases being requested.

TABLE V-

PG&E Recorded and Requested
Total Conservation Expenditures
1982 through 1984
($000)

	1982 Authorized	1982 Recorded	1983 Recorded Jan.-Aug.	1983 Total Budget*	1984** Requested
General Rate Case Programs:					
Builder Conservation	$ 1,900	$ 1,047	$ 594	$ 2,442	$ 2,489
Appliance Efficiency	3,874	4,409	3,917	7,347	9,416
Master Meter Conversion	387	306	387	813	2,781
Energy Management (MGT)	17,273	12,874	7,944	15,663	20,528
Agricultural Energy MGT	1,883	1,221	1,058	1,791	2,132
Energy MGT Incentives	8,500	1,599	9,222	32,545	38,159
Technical Support	2,043	1,907	890	1,456	2,540
Communication and Seminars	1,268	1,529	673	819	4,982
General Customer Inquiries	1,800	1,949	2,689	1,800	2,054
Program Evaluation	1,100	579	296	1,100	1,722
Subtotal	$40,028	$27,420	$24,670	$65,776	$ 86,803
Community Service***	1,834	1,743	1,132	1,896	2,229
Stockton Training Center***	1,087	415	307	529	1,529
Total	$42,949	$29,578	$26,109	$68,201	$ 90,561
Residential Conservation Services (RCS)		12,556		15,050	19,097
Conservation Financing Adjustment (ZIP)		8,972		53,561	75,614
Solar Financing Adjustment		7,636		11,130	7,670
TOTAL CONSERVATION		$58,742		$147,942	$192,942

* Of the total 1983 budget, PG&E expects to spend $21,279,000 between September and December of 1983; $22,902,000 will be encumbered but unspent as of January 1, 1984. Major encumbrances include energy management incentives ($17,177,000), energy management audits ($3,419,000), and builder conservation ($1,348,000).

** Rate case expenditure requests escalated with escalation rates adopted in this decision.

*** To be transferred to RCS and ZIP programs.

We adopt staff's policy guidance regarding conservation budgets in 1984 and 1985, that is, we evaluate individual proposed programs with the following three objectives in mind:

a. Maintain PG&E's conservation expenditures at about the levels authorized in the general rate case. Excluding the two programs which are transferred to ZIP and RCS, this is a range of $40 million to $50 million, in current dollars.

b. Cut conservation programs that now appear ineffective and increase or add programs that can help customers who have had limited benefits from existing programs.

c. Maintain the existing framework for cost-effective conservation programs.

2. Conservation Budgets

Table V-2 compares PG&E's requests, staff recommendations, and adopted budgets for 1984 for each of PG&E's conservation programs funded through the rate case, in 1981 dollars. Application of the adopted escalation rates results in a total authorization of $54.3 million in 1984 dollars. It should be noted that PG&E has agreed with the staff recommendation that the "Community Service" program element (line 4) and the "Stockton Training Center" element (line 12) be transferred to the RCS and ZIP programs. With these two deletions conservation can be divided into two areas: technical programs (lines 1-7) and support programs (lines 8-11).

Table V-2

Pacific Gas and Electric Company
Proposed and adopted 1984 Energy Conservation Expenditures
Test Year 1984
(Thousands of 1981 Dollars)

Name of Program	PG&E	Staff Recommended	Staff Minimum	Adopted
Builder Conservation	$ 2,181	$ 1,863	$ 1,363	$ 1,363
Appliance Efficiency	8,401	9,781	8,521	6,211
Master Meter Conversion	2,471	2,471	1,500	750
Community Service	1,887	(a)	(a)	0
Energy Management (MGT)	17,151	14,991	12,271	13,720
Agricultural Energy MGT	1,783	1,783	1,500	1,500
Energy MGT Incentives	34,251	25,384	16,316	16,316
Technical Support and Demonstration	2,196	2,196	1,756	1,756
Communication and Seminars	4,431	1,401	1,401	1,401
General Customer Inquiries	1,636	1,867	1,867	1,636
Program Evaluation	1,517	2,207	2,207	2,207
Stockton Training Center	1,330	(a)	(a)	0
Total	$79,235	$63,944	$48,702	$46,860

(a) To be transferred to RCS & ZIP.

The support programs are considered to complement technical programs. No energy savings are explicitly associated with these programs; rather all energy savings are included in the savings of the technical programs.

The basic position of the staff in the Energy Conservation Branch (ECB) of Utilities Division concerning PG&E's program is stated on page 1-5 of Exhibit 132 as follows:

> "The results of the investigations in these proceedings confirm that there is a tremendous amount of energy that can be saved in all sectors of the economy. All the programs being

recommended by PG&E are very effective energy savers. The level of funding is the only limitation on the amount of energy that can be saved. PG&E has wisely incorporated conservation into its long range resources plan. The ECB strongly recommends that the Commission continue its vigorous energy conservation and management policies."

The cutbacks in PG&E's request recommended by the ECB staff reflect a budget that ECB staff believe "is about the most PG&E can effectively manage." (Exhibit 132, p. 1-6) Because of the underexpenditures that occurred in 1982, the staff questions PG&E's ability to effectively implement and control the rapid program expansion requested. The staff's primary program cuts are in advertising and promotional expenses.

ECB staff presented an alternative level of funding for Commission consideration which approximates the 1983 authorized budget and which is also shown in Table V-2. Staff termed it a "minimum" budget and does not recommend it. This budget represents about a 24% cut from the level recommended by ECB staff. However, the reductions vary from program to program, with smaller cuts allocated to the most effective energy saving or important support programs.

We note that PG&E's 1984 budget request represents approximately a 61% increase over the 1983 rate case authorization, and a 98% increase over the 1982 authorization in constant dollars. Similarly, ECB staff's recommendation represents increases of about 36% and 67% over 1983 and 1982 authorizations, respectively.

Consistent with the policy recommendations presented by staff witness Ahern, we adopt a conservation budget similar to the "minium" budget presented by ECB staff. Differences are detailed in the following sections. Budgets for 1985 will be determined through the attrition process and will only reflect increases due to inflation.

We give PG&E discretion to reallocate up to $2.5 million to or from any single conservation program without further Commission authorization, consistent with current policy. Thus, savings in one program area can allow increased expenditures elsewhere.

3. Cost-Effectiveness of Conservation Programs

Extensive evidence was entered into the record regarding the cost-effectiveness of conservation programs from the four perspectives: societal, utility, participant and nonparticipant. Staff also ran "high" and "low" scenarios examining the effect of such factors as oil escalation rates and discount rates on the programs' cost-effectiveness. While staff assumes that the value of demand reductions is equal to a combustion turbine, PG&E presented two sets of calculations, one of which adjusts the combustion turbine to recognize the reduced value of demand reductions during periods of high reserve margins.

The cost-effectiveness calculation from the utility perspective estimates the effect of a program on utility revenue requirement savings in capacity and energy costs avoided by the utility as a result of implementing the program. The costs of the program from the utility perspective are the revenue requirements associated with the program, including the annual fixed charges associated with any capital investment, as well as any one-time and/or ongoing program expenses.

The objective of the nonparticipant (or ratepayer) perspective is to estimate the extent to which rate levels will be affected by the program. The benefits to nonparticipants are identical to those included in the utility perspective, since the revenue requirement savings associated with avoided capacity and energy costs are passed on the utility's ratepayers. The costs to ratepayers, on the other hand, not only include the revenue requirements of the utility, but also include the revenue losses that are associated with the program. These revenue losses, which arise because program participants experience bill reductions due to lowered consumption, shifts in demand, and/or certain incentive payments, must be recovered from ratepayers as a whole. Therefore, the costs of the program to utility ratepayers are higher than the program revenue requirements.

The participant perspective estimates the attractiveness of the program to potential program participants. The benefits of the program to program participants (i.e., reduced bills) are exactly equal to the ratepayer revenue losses. Participant costs include participant out-of-pocket expenses, as well as the costs of increased discomfort or inconvenience that the participant may experience as a result of program participation. Costs due to increased discomfort or inconvenience, which are mainly applicable to load management programs, are extremely difficult to quantify and current analyses do not quantify these costs. Participant costs are reduced by any federal or state tax deductions or credits that may be utilized as a result of participation. If a program is voluntary, it can be assumed that the benefits of the program are perceived by the participants to exceed the costs.

Finally, the societal perspective is designed to estimate the overall economic effects of a program on society as a whole, and therefore attempts to capture all programs costs and benefits regardless of who incurs them. The benefits of a program to society include the societal avoided costs of capacity and energy. In addition, societal benefits may include certain additional benefits such as environmental and national security externalities. These externalities have not been included in calculations of conservation and load management cost-effectiveness. The costs of the program to society include the costs of the resources consumed by the program, so that a capital investment is valued at the actual cost in the year the investment is incurred. Societal costs also include administrative and operating expenses. In addition, the cost of the program to participants (including the costs of discomfort and inconvenience) are also a component of the societal cost.

All conservation programs but one passed the participant, utility and societal tests in both PG&E and staff analyses. A program must have a benefit-cost ratio greater than one and a net present value greater than zero to pass a given test. The one program that experienced some difficulty was the Master Meter Conversion program, which failed the societal test (gas and electric) and participant test (gas and electric) for the "low" indicator values in the staff analysis, and the societal test (gas) for the "medium" values.

All the gas programs fail the nonparticipant test in both PG&E and staff analyses, with benefit-cost ratios between 0.67 and 0.78 under staff's "medium" scenario. All electric programs fail the nonparticipant test according to the PG&E evaluation with benefit-cost ratios ranging between 0.81 and 0.97. The benefit-cost ratios for all electric programs are close to one (0.95 to 1.04) in the staff's "medium" analysis, except the Master Meter Conversion program (0.87).

ECB staff devoted considerable discussion to why, in its opinion, the results of the nonparticipant test should be interpreted with extreme caution. The relevant factors cited by staff include:

1. In the aggregate, the six programs analyzed and their related support programs will cause the average residential nonparticipant's bill to increase by only 56 cents (ECB estimate) to $1.10 (PG&E estimate) per year over the life of the measures (though staff estimates the first year's impact to be $9.10).

2. The nonparticipant test is inherently less accurate than the other three tests because it requires the forecasting of both marginal costs and average costs and relies on the difference between these two streams.

3. The societal test should be given greater weight when the impact on nonparticipants is minimal, because a substantial portion of the societal benefits accrue to nonparticipants. Further, important societal benefits and costs due to conservation include the downward pressure on world energy prices, job creation, and reduction in air pollution (benefits), possible increases in customer discomfort and inconvenience (costs), and unknown impacts on system reliability (benefit or cost).

4. Market research indicates that less than one-quarter of PG&E residential ratepayers have never participated in PG&E conservation programs (including informational programs). Further, all PG&E ratepayers participate in the Conservation Voltage Reduction program, which was not included in the staff calculation of benefit-cost ratios. The average residential ratepayer will receive a net benefit in 1984 from that program of $7.96.

Many of staff's criticisms of the nonparticipant test are valid. In several past decisions, we have agreed that the nonparticipant test should not be relied upon exclusively in the evaluation of resource additions, including load management and conservation programs. Although the nonparticipant test indicates how equitable the individual programs are to nonparticipants, complete reliance on this test could result in another inequity: namely, programs could be dramatically cut back or eliminated before nonparticipants have an opportunity to take advantage of them.

At the same time, we know that, realistically, the utility's conservation programs will never provide for 100% ratepayer participation, thereby eliminating nonparticipant inequities.

There remain hard-to-reach segments of the population and we must continue to be concerned about the overall impact of utility programs on their monthly bills. Further, conservation programs must be judged individually on their merits, not just as part of the overall effort, and the nonparticipant test provides a valuable comparison among programs.

While we will not deny funding for any of PG&E's proposed conservation programs based solely on their failure to meet the nonparticipant test, this is an important factor in our decision to limit the overall level of funding. We instruct PG&E, within the budgets authorized today, to direct its expenditures carefully to the most cost-effective portions of the proposed programs, to further minimize the impact on nonparticipants.

4. Specific Conservation Programs

For each conservation program discussed below, the heading provides PG&E's 1984 request, staff's recommendation, and the adopted expenditure level, all in 1981 dollars.

a. Builder Conservation - $2,181,000; $1,863,000; $1,363,000

The objective of this program is to encourage the use of energy efficient gas appliances in new homes through cash incentives. PG&E will offer builders an incentive of $100 to install gas appliances (furnance, water heater, and range) and a gas clothes dryer stub in each new home. PG&E estimates that with the incentive, builders will still have to pay an additional $50 per dwelling because gas appliances are more expensive than electric. PG&E's goal is to qualify 10,000 new homes in 1984 and 15,000 in 1985 as natural gas homes.

The staff recommended reduction of $318,000 includes $114,000 for trophies and promotion and $204,000 as a reserve to fund a pilot program for promoting high efficiency HVAC (heating, ventilation, and air conditioning) systems. We agree with the staff disallowances and further adopt a Builder Conservation program budget of $1,363,000, which is the "minimum" budget presented by staff.

b. Appliance Efficiency -
$8,401,000; $9,781,000; $6,211,000

The objective of this program is to encourage residential customers to replace older inefficient appliances with more efficient models and to select energy-saving models when purchasing new major appliances. In areas where natural gas is available customers are encouraged to convert their electric appliances to high efficiency gas appliances. Details of PG&E's planned incentive levels, number of customers reached and the cost-effectiveness of the program subcomponents are contained in PG&E and staff exhibits.

The staff recommendation is $1,380,000 greater than the amount requested by PG&E. That amount is arrived at by disallowing $300,000 for television advertising, $630,000 for microwave oven incentives, and $600,000 for conversion to pilotless gas clothes dryers. These disallowances were more than offset by a recommended increase of $2,910,000 to fund removal of 30,000 additional second refrigerators and incentives for the purchase of 20,000 additional high energy refrigerators.

We note that staff's "minimum" budget of $8,521,000 for this program is larger than PG&E's request for 1984. While many elements of this program appear worthwhile, some budget cuts are in order. We fund this program for 1984 at $6,211,000, which is the staff's "minimum" budget less the $2,910,000 increase staff recommended for expanded refrigerator incentives, plus the $600,000 gas clothes dryer incentives which staff would disallow. We note that incentives for second refrigerator removal and the purchase of high energy refrigerators appear to be among the least cost-effective (to the nonparticipant) program elements. Expansion of these incentives does not appear warranted. We agree with staff that the microwave oven incentives should not be funded. However, the gas clothes dryer incentives appear to be very cost-effective. While we will not disallow this funding, the clothes dryer incentives should be discontinued in 1985 if they prove unpopular, as staff projects.

We note that, even with the substantial cuts from the program levels recommended by staff, the funding level is approximately 70% higher than that authorized for 1982 in the last general rate case, in constant dollars.

c. Master Meter Conversion -

$2,471,000; $2,471,000; $750,000

The master meter conversion program encourages building owners to convert from master metering to individual metering. PG&E's goal is to convert 11,400 electric meters and 8,650 gas meters during 1984. About 78,000 electric units and 58,000 gas units are eligible for conversion.

The staff concurs in this funding level. However, it notes that customer response to this program, which was implemented in 1977, has been poor. The $100 incentive is small compared to conversion costs of $300 to $1,000 per unit for electric conversions and $500 to $1,000 per unit for gas. Staff recommends that PG&E provide low interest loans for master meter conversion. This would solve the problem of up-front capital requirements.

In its "minimum" budget, staff cuts this program to $1,500,000. Given the poor customer participation and low PG&E expenditure levels in the past, we believe that even further budget reductions are appropriate, though we continue to support the goals of this program. Since the market is limited, the start-up costs for a loan program cannot be justified at this time. We will authorize $750,000 for this program in 1984. This funding level is comparable to that budgeted for 1983, and represents almost a tripling of the 1982 expenditure level.

d. Community Service

The staff recommends and PG&E concurs that this program should be transferred to the RCS and ZIP programs. We adopt the recommendation.

e. Energy Management -

$17,151,000; $14,991,000; $13,720,000

The Energy Management program provides energy management audits to commercial, industrial and institutional customers. Under the audit plan established by the CEC, the largest 743 large customers (over 500 kW) must be audited. The other 270,000 customers must be made aware of PG&E's conservation activities and audited upon request.

The staff recommends a disallowance of $611,000 in audit labor cost and the entire $1,549,000 marketing component of the program. PG&E argues that the marketing component is small (6% of program cost) and that it is necessary to reach the hard-to-penetrate small commercial market. Also, PG&E believes that as smaller customers are contacted and more post audits are conducted additional labor costs will be required to maintain momentum.

We agree with PG&E regarding the marketing component. In D.93887 we expressed our concern regarding equity for small commercial customers. Particular efforts should be made to reach these customers. We authorize funding of $13,720,000, which is staff's "minimum" budget of $12,271,000 plus the $1,549,000 marketing component which staff would disallow.

Staff expressed concern about PG&E's capability to comply with CEC's Energy Management Standards Program and to achieve equity among customer classifications, and about PG&E's methods of measuring and reporting energy savings. Staff recommends, and we adopt, a requirement that PG&E file certain plans with its regular 1984 annual conservation plans which PG&E shall provide to the staff within 60 days following the effective date of this decision. Staff should monitor this program carefully to ensure its effectiveness.

f. Agricultural Energy Management -
$1,783,000; $1,500,000; $1,500,000

Agricultural Energy Management is a longstanding program to improve efficiency through pump tests, optimal water discharge analysis, irrigation system analysis, and agricultural facility audits. These services are designed primarily to improve the efficiency of pumping and irrigation energy uses, which account for more than 80% of the electrical energy used by agricultural customers.

The staff recommends the full requested funding of $1,783,000 and presents a "minimum" budget of $1,500,000. We adopt this level of $1,500,000.

g. Energy Management Incentives -
$34,251,000; $25,384,000; $16,316,000

This program is intended to make selected energy conservation measures more economically attractive by offering commercial, institutional, and industrial customers financial incentives for installing energy saving equipment or devices. This program is promoted through the Energy Management audits for the commercial sector. It is the largest single element of the conservation program, comprising about 43% of the entire requested amount.

PG&E's market research studies show the need for financial incentives to overcome the long payback periods which make customers reluctant to install devices with high initial costs.

The staff recommends a funding level of $25,384,000 compared to the utility's requested level of $34,251,000 and presents a "minimum" budget of $16,316,000. We will adopt $16,316,000. This budget is still substantially larger than that authorized for 1982 and 1983 in the last rate case. While we have allowed PG&E to expand this program in 1983 far beyond the levels contemplated in that rate case, we do not believe this trend should be continued. The Energy Management audit program should increase customer awareness of the benefits of conservation actions, which should reduce the need for incentives to the commercial sector.

Staff recommends low interest loans for small commercial customers as alternatives to cash incentives for weatherization of building envelopes. This would reduce first-year costs to ratepayers and to participating customers. As for the master meter conversion program, we reject this proposal. Commercial customers have reasonable access to financial markets. Further, the adopted incentive program should provide sufficient impetus to these customers. We see no need to impose the administrative burden of such a program on PG&E's ratepayers.

h. Technical Support Program -

$2,196,000; $2,196,000; $1,756,000

This program provides expert technical assistance to PG&E's customers and personnel on matters related to the efficient use of energy primarily in the nonresidential sector. A detailed description of the program is contained in PG&E's Exhibit 11.

The staff recommends that this program be funded to the full amount requested by PG&E to help small commercial customers in particular. The staff is also concerned that cuts in this program could limit PG&E's efforts in meeting the goals of its nonresidential energy management program.

As an alternative, staff's "minimum" budget level is $1,756,000. Since there appears to be substantial overlap between this program and the programs it supports, this reduction is appropriate.

i. Communication and Seminars -

$4,431,000; $1,401,000; $1,401,000

The objective of this program is to meet the communication and media needs of major conservation programs by supplying seminar workshop materials, writing assistance, editing, and graphic coordination for those programs. Also, the program administers and coordinates seminars for commercial, industrial, and agricultural customers. Commission staff has reviewed this program and supports it. The staff analysis does point out, however, that the $4,431,000 requested to fund this program includes $3,030,000 for media advertising should the need for summer and winter load reduction arise. The staff recommends that this amount be disallowed if any of the Diablo Canyon and Helms units become operational prior to June 1, 1984. We note that the staff recommended funding level is comparable to past expenditures in this area. We authorize $1,401,000 for this program.

j. General Customer Inquiries -

$1,636,000; $1,867,000; $1,636,000

This program is needed because customer service employees who normally handle other types of inquiries are spending significant amounts of time handling conservation inquiries. Those activities were singled out for reimbursement through the conservation program in the last PG&E general rate case; this procedure should be continued. The request of $1,636,000 is lower than the recorded 1982 expenditures. The Commission staff feels that this funding level is inadequate and recommends that $1,867,000 be authorized to maintain the same level of service. We will not adopt the staff recommendation, but will fund the program at the full level requested by PG&E.

k. Program Evaluation - $1,517,000; $2,207,000; $2,207,000

This program is designed to evaluate the effectiveness of the various conservation programs. PG&E will refine its conservation savings quantification methodology, conduct verification studies on estimated savings accomplishments, identify opportunities for further improvement in program efficiency and productivity, study conservation potential and innovative marketing strategies, and refine overall conservation planning and forecasting techniques.

The staff recommends the funding level requested by PG&E, and also transfers $690,000 for marginal cost studies to the program evaluation budget from the load management area.

The staff analysis of PG&E's program evaluation efforts, in Exhibit 134, Appendix A, shows several defects in PG&E's prior efforts and offers recommendations on improving those efforts including the recommendation that PG&E file a quarterly report. The staff shows that the requested program evaluation levels are at approximately the same levels as other major California utilities on a percentage basis. The staff considers its recommended expenditures to be the bare minimum to ensure that PG&E ratepayers get their money's worth out of the millions of dollars being spent on conservation and load management. We agree with the staff's comments.

We emphasize that evaluation is a crucial component of PG&E's conservation program, and share staff's concerns about past underexpenditures in this area. Careful analysis should precede any new program implementation; and on-going evaluation, and adjustments if warranted, are essential to maintaining the most cost-effective effort possible. Because of our strong endorsement of a vigorous evaluation program, we adopt the staff's recommended funding level. We also suggest that PG&E follow as closely as possible the other staff recommendations contained in Exhibit 134 regarding its research.

We note that PG&E did not present evidence regarding its conservation savings quantification results in the record, nor did staff discuss the reasonableness of the energy savings assumed for each program. Since this is a crucial component of PG&E's and staff's cost-effectiveness analyses, we instruct PG&E and staff to present testimony on this matter in PG&E's next general rate case.

5. Marketing Service Expenses

Marketing Service expenses were removed from the conservation budget by D.93887 in PG&E's last rate case. Accordingly, PG&E placed the Marketing Services activity in a separate budget category within the Customer Service and Information accounts (Accounts 907, 908, 909, and 910). Conservation, Marketing Service, and Load Management are the only components of these accounts. Since staff addressed Marketing Services in its conservation exhibits, we will discuss the program at this time.

Marketing Services provide customers with "specialized and technical assistance, as well as educational information and advice on the use of electricity in a safe, efficient, productive, and environmentally sound manner" (PG&E's Exhibit 8, page 9-5). Examples of Market Service activities which PG&E provides include:

1. Communications with customers, governmental agencies, and others regarding the general energy situation, service reliability, energy availability, and prospective energy costs, and

2. Assistance to governments in the application of electrical codes, in development of programs for the conversion of existing overhead lines to underground; and in the design of new or modified street lighting systems.

PG&E used the level of expenditures authorized in D.93887 for 1982 to obtain its requested 1984 expenditure of $4,530,000 in 1981 dollars. Staff agrees that funding should be maintained at 1982 levels, but notes that PG&E did not de-scalate the 1982 expenses to 1981 dollars. Thus, staff recommends funding of $4,167,000 in 1981 dollars. We adopt the staff estimate.

6. <u>Conservation and Load Management Underexpenditures</u>

An issue of some import raised by staff in this proceeding is how we should treat historical underexpenditures of conservation and load management funds. In D.93887 in PG&E's last general rate case we provided that any conservation and load management funds not expended in the test year would be carried forward to the next year. The implication was that any funds not spent in either the test year or the attrition year would be applied to the next general rate case revenue requirement. Subsequently by Resolution No. E-1979 we addressed the issue of load management and conservation underexpenditures carryover. In Resolution No. E-1979 we found that:

> "5. PG&E has agreed both in this filing as well in the current rate proceeding A.82-12-48 that by October 1, 1983, it will provide the Commission staff with an estimate of year-end 1983 Conservation and Load Management expenditures, to be comprised of two parts: (1) data on actual expenditures and encumbrances through the first 8 months of 1983, and (2) an estimate of expenditures and encumbrances for the remaining 4 months of 1983. Since October 1, 1983 is a Saturday, the next business day Monday, October 3, 1983 should be the submittal date. This information is to be presented by program as identified in A.82-12-48 and which is consistent with present accounting procedures.
>
> "6. PG&E has agreed that 1982 and 1983 authorized but unexpended or unencumbered Load Management and Conservation Funds, plus accrued interest, may be credited against 1984 Load Management and Conservation funding

> which will be established in PG&E's current rate proceeding (A.82-12-48). Interest will be based on one-half of each year's beginning plus end-of-year fund balance as recorded for year 1982 and estimated for year 1983, at the annual average short-term 90 days commercial paper interest rate which for calendar year 1982 was 11.89%."

In that resolution we provided that PG&E would supply an updated estimate of the 1982-83 underexpenditures. PG&E has provided that report with the following estimate:

Energy Conservation	
Interest on 1982 Conservation Carryover	$ 927,339
Load Management	18,609,324
Interest on 1982 and 1983 Load Management Carryover	1,773,790
Total	$21,310,453

Our staff has also filed a report which recommends certain modifications to PG&E's calculations of the revenue credit. First, the staff recommends that we treat the Conservation Voltage Reduction Program (CVR) expenditures in the same manner. While PG&E projects that it will spend its 1983 CVR budget of $9,582,000 by the end of the year, staff forecasts a CVR surplus of about $5.6 million based on low expenditure rates for the first eight months of 1983. D.93887 provided that carryover treatment would be applied to Conservation and Load Management and no other programs. Resolution E-1979 did not provide for any special treatment of the CVR program either. We note also that PG&E plans to expend all authorized CVR funds in 1983. We will therefore not adopt the staff recommendation.

Staff further recommends that interest should accrue on year-end unexpended conservation funds whether they are encumbered or not. PG&E argues that interest should be calculated only on the unspent funds which are not encumbered. We note that PG&E estimates that $20,801,000 in unspent conservation funds will be encumbered as of January 1, 1984; PG&E proposes to pay no interest on this amount. In Resolution No. E-1979 we clearly intended that unspent but encumbered funds should be included in the interest calculation:

> "Interest will be based on one-half of each year's beginning plus end-of-year fund balance as recorded for 1982 and estimated for year 1983."

We stand by that determination.

However, staff incorrectly interpreted our intent by including interest on 1981 carryovers. The calculation should begin with 1982 expenditures.

With these modifications to both PG&E's and staff's calculations, we arrive at the following determination of the 1984 revenue credit:

Interest on 1982 and 1983 Energy Conservation Budget Carryovers	$ 2,613,248
Load Management Excess Revenue Requirements for 1982 and 1983	18,609,324
Interest on Load Management Funds	1,773,790
Total	$22,996,362

Another issue is when this credit should be applied against the revenue requirement. PG&E argues that about half should be applied toward the revenue requirement of 1984 and half in 1985 because the application of the entire amount in 1984 would distort the attrition allowance mechanism unless further evidence is received.

Consistent with the staff recommendation and with Resolution No. E-1879, we reiterate that the full amount of $22,996,362 should be credited against the 1984 revenue requirement. We authorize an equal 1985 attrition adjustment to recognize that this is only a one-year credit.

A reevaluation of the above credit calculations will be needed once actual 1983 conservation and load management expenditures are determined. We order PG&E to provide true-up calculations and supporting data as part of its "Energy Management and Conservation Activities Report for 1983" which is filed in compliance with D.86501. Staff will also provide an independent analysis of PG&E's

filing with D.86501. Any amount by which the authorized credit differs from the true-up results will be carried forward, with interest, and will be reflected in the 1985 attrition adjustment.

The final issue is how these items will be treated in the future. In order to clarify our position we will provide that:

1. Conservation, Load Management, CVR, and 12-21kV conversion funds not spent in the test year will be carried forward with interest to the attrition year. The computation will be done once final test year expenditure levels are known.

2. Interest will be based on one-half the 1984 end-of-year balance, including encumbered but unspent funds, at the annual average short-term 90 days commercial paper interest rate.

3. Any carryover of unexpended funds during the attrition year will be accounted for in PG&E's next general rate case in a manner to be decided therein.

B. Load Management

1. Policy Considerations

PG&E requests $52.2 million to fund electric load management programs, and $2.9 million to fund gas load management programs in 1984. These amounts are in 1984 dollars and include both capital and expense components. PG&E had originally requested $75.9 million in total load management financing but reduced its request during the proceeding.

ECB staff recommends substantially lower funding levels of $17.7 million for electric load management and $1.7 million for gas load management in 1984. These amounts are derived in part from a ratio of recorded over authorized expenditures for 1982, which is then applied to PG&E's proposed 1984 budget.

The marked difference in funding levels between the company and the ECB staff stems largely from the divergent policy perspectives each adopts in evaluating both the overall need for capacity reductions through load management in this test period and the effectiveness of individual programs in meeting that need. We will consider both perspectives in determining a reasonable level of load management funding.

A fundamental issue facing us is to decide the extent of load management activity in the short term when PG&E's level of capacity is expected to be adequate through the 1980's. In making this decision, we must also recognize the value of determining whether load management can provide cost-effective capacity when it is needed in the long term, or mid-1990's.

PG&E recognizes the 1984-1985 time period as an opportunity to gradually put into place those load management programs that will eventually be needed to supply long-run capacity needs. Programs that will be needed must be developed, tested, and perfected now. (Exhibit 14, pp. 3-17.) PG&E also believes that high energy costs will prevail during 1984 and 1985, leading customers to welcome service options as a means to exert some control over their energy bills.

The policy perspective proposed by Ahern of our staff is more cautious than PG&E's. He points out that there is no need for expanded load management to increase capacity since adequate capacity exists and will continue to exist for the next few years. Ahern recommends for the test period that PG&E continue clearly successful load management programs. He further recommends that PG&E fund new experimental programs. However, programs should be expanded only if it can be shown that they are more cost-effective than adding capacity, making out-of-state purchases or operating Helms, and then only at the time the capacity is needed.

Ahern acknowledges that experimental programs can be useful hedges against uncertainty, but asserts that major expenditures are not necessary at this time. In sum, Ahern indicates that caution should be the preferred strategy, especially since PG&E seems to have proposed larger funding than can be used effectively on clearly successful programs.

These perspectives are not necessarily incompatible. We agree with staff witness Ahern that we ought to proceed cautiously but deliberately in the direction of providing cost-effective load management capacity when such capacity eventually is needed. In our view this means careful evaluation of the viability of individual programs in meeting future capacity needs before allowing major expansions.

Ahern lists four major objectives which load management programs can serve. Foremost is the objective of encouraging electric load shifting from peak to off-peak hours in order to reduce overall capacity requirements. Secondly programs can provide users with accurate economic signals of the cost of their energy usage so that they can make economically efficient decisions on usage. Thirdly, load management programs can promote conservation of energy. Lastly, programs may provide rate options to larger users of electricity which result in lower rates. While we recognize that each of these objectives is important, above all load management should be considered a resource which must compete economically with other forms of resources. Accordingly, we must evaluate the need to expand significantly load management programs in light of their ability to provide cost-effective capacity. At the same time we do not wish to dismantle the framework which has developed to date in the area of load management, as we are mindful of the need for PG&E to remain prepared to meet the capacity requirements of the future.

We find that the perspective offered by Ahern defines the perspective we wish to adopt in determining a reasonable load management program for the test period.

PG&E has proposed greatly expanding existing programs and implementing new ones in order to accomplish some or all of these objectives. Table V-3 is a comparison of recorded and PG&E's requested expenditures for the major categories of load management. Proposed increases from 1983 to 1984 for electric load management range from about 30% for residential programs to about 130% for agricultural programs. PG&E requests a 700% increase in the gas load management area over the expected 1983 expenditure level.

TABLE V-3

Pacific Gas and Electric Company
Load Management Expenditures
Current Year Dollars
(000s Omitted)

	1982* Recorded	1983 Recorded Jan-Aug	1983 Total Budget*	1984 Proposed	1985 Proposed
Residential	$10,048	$ 7,756	$13,520	$17,671	$20,739
Agricultural	2,472	2,488	3,699	8,519	10,147
Commercial/Industrial	4,576	3,230	5,029	8,292	11,684
General and Support Programs	7,474	6,364	13,133	17,678	19,142
Total Electric Load Management	14,570	19,838	35,381	52,160	61,712
Total Gas Load Management	455	331	416	2,910	2,962
Total	$25,025	$20,169	$35,797	$55,070	$64,674**

* In PG&E's last rate case, the Commission authorized expenditures of $53.2 million in 1982 and $31.9 million in 1983. PG&E expects that about $24.3 million will remain unspent and unencumbered at the end of 1983.

** Exhibit 236 shows a revised total estimate of $63,687. The difference is due to lower assumed escalation rates.

Overall, PG&E requests a 54% increase for 1984 over 1983 planned expenditures. This increase is substantial and does not appear to comport with PG&E's desire to gradually increase load management funding, or with Ahern's proposal to cut back substantially on load management funding.

2. Load Management Budgets

The following table compares PG&E's requests, staff recommendations, and the adopted budgets for 1984 for each of PG&E's load management programs, in 1984 dollars.

TABLE V-4

Pacific Gas and Electric Company
Proposed and Adopted Load Management Expenditures
Test Year 1984
(Thousands of 1984 Dollars)

Name of Program	PG&E	Staff	Adopted
Residential			
Air Conditioner Direct Control	$ 5,608	$ 2,930	$ 3,376
Water Heater Direct Control	190	0	164
Time-of-Use (TOU)	11,460	1,328	3,000
Swimming Pool Pump Timer	413	386	384
Agricultural			
Large Customer TOU (PA-2)	5,133	3,188	1,000
Small Customer (PA-3)	1,871	0	500
Interruptible (PA-T)	355	296	329
Odd-Even Service (PA-R)	1,160	1,010	1,075
Commercial/Industrial			
Mandatory TOU A-23/A-22/A-21B	150	28	144
A-23, Special Condition 10	300	99	278
A-22, Special Condition 10	167	41	154
Group Load Curtailment	3,607	1,806	2,000
A-18B Interruptible	130	60	119
Small Commercial Interruptible	99	36	90
A-21A Optional TOU	1,312	0	440
A-7 Optional TOU	1,591	0	560
Real Time Pricing	438	0	419
Commercial A/C Direct Control	498	0	462
General and Support Programs			
Community Electricity Management	3,465	1,114	1,000
Load Analysis			
a. End-Use Analysis	5,174	1,973	4,796
b. Metering of Small Power Producers	323	311	299
c. PURPA and Class Load Analysis	185	80	170
Data Acquisition System	826	416	776
Demand Control Center	266	138	246
Energy End-Use Data Collection	1,967	1,416	1,782
Marginal Cost/Economic Analysis	739	0	0*
Metering Systems Evaluation	1,539	651	1,488
Administrative Functions	3,194	0	1,634
Total Electric Load Management	$52,160	$17,713	$26,685

TABLE V-4 Cont.

Name of Program	PG&E	Staff	Adopted
Gas Load Management			
End Use Analysis	$ 574	$ 213	112
Energy End-Use Data Collection	1,967	1,460	$ 388
Marginal Cost/Economic Analysis	369	0	0*
Total Gas Load Management	$ 2,910	$ 1,673	$ 500
TOTAL	$55,070	$19,386	$28,185

* Funded through the Conservation budget.

We authorize a total of $28.2 million for load management programs in 1984, slightly over half PG&E's requested budget. Of this amount, $26.7 million is for electric load management programs. We fund gas load management, which consists solely of end-use data collection and analysis, at $500,000. Budgets for 1985 will be determined through the attrition process and will only reflect increases due to inflation.

While we did not adopt the extensive budget reductions proposed by our staff, we did give serious consideration to the fact that PG&E, for whatever reason, did not spend the amounts authorized in the last two years for load management. PG&E spent $25.0 million on load management in 1982, and carried over about $28 million of unspent funds to 1983. We observe that PG&E spent $20.2 million in the first eight months of 1983, and intends to spend $15.6 million in the last four months of 1983, for a total 1983 expenditure of $35.8 million. However, even if PG&E meets its ambitious spending goals for the last third of 1983, over $24 million of the 1982-83 authorization will remain unspent. (As discussed elsewhere, the excess revenue collected during those two years will be used, with interest, to reduce the 1984 revenue requirement.)

We also question whether PG&E can effectively carry out the large number of experimental programs planned for the test year. PG&E proposes to undertake roughly 20 separate load management programs, several of which would be new offerings. While we do not explicitly deny authorization for any particular experiment requested, we expect PG&E to reevaluate the efficacy of pursuing all options simultaneously, particularly since new capacity needs will not exist for the PG&E system for several years.

Further, it appears to us that some of the proposed experiments may be larger than necessary to provide adequate experimental data at the least reasonable cost. The success of PG&E's load management efforts during the test period must not be measured by the number of devices installed. Instead, the emphasis should be on careful experimental design so that the comprehensive information necessary to allow thorough evaluation of the programs and their effectiveness can be obtained.

We give PG&E discretion to reallocate up to $2.5 million to any single load management program or from any program except the residential air-conditioner cycling and time-of-use programs without further Commission authorization. Thus, streamlining or deferment of certain programs can allow increased expenditures in other program areas.

The authorized budget reflects our policy to have PG&E view the next two years as a unique opportunity to make careful and thorough analyses of the load management experiments which it has conducted to date. We believe that in view of the window provided before PG&E needs additional capacity, PG&E should take this opportunity to determine conclusively whether these programs can be continued cost-effectively.

Major capital expenditures have already been made to initiate several of the programs and wide customer participation has been achieved. Thus, important strides can be made in evaluating the individual experiments without requiring major capital expenditures during the test period.

The authorized budget also reflects our concern that nearly all of the load management programs fail to be cost-effective to the nonparticipant ratepayer, as discussed in the next section. While we have not reduced funding for a particular program solely because of this, we cannot ignore the fact that nonparticipant ratepayers are paying higher rates to fund these programs without offsetting benefits.

In view of the above, we believe that it is prudent to proceed cautiously, yet deliberately so that when capacity is needed once again, the groundwork will have been laid to allow implementation of cost-effective load management programs.

3. Cost-effectiveness of Load Management Programs

Before evaluating each of the program areas and individual programs, we must consider the criteria we will use to determine which programs are "clearly successful," or cost-effective. Ahern defines that a program is cost-effective if it is less expensive than adding new capacity, making out-of-state power purchases, or operating Helms. This is generally consistent with the cost-effectiveness methodology used by ECB staff and PG&E in this proceeding.

The cost-effectiveness of load management programs has been evaluated from the perspectives of the participant, nonparticipant (also called ratepayer), utility, and society. PG&E also analyzes cost-effectiveness both in the short term, using its Energy Reliability Index (ERI), which recognizes the system's current reduced need for capacity, and in the long term, without the ERI. Table V-5 and Table V-6 summarize, respectively, PG&E's and staff's cost-effectiveness results for the proposed load management programs.

TABLE V-5

SUMMARY OF LOAD MANAGEMENT
PROGRAM COST-EFFECTIVENESS RESULTS
1984

Program Title	Adjusted (Short-Term) Utility	Society	Ratepayer
Residential			
A/C Direct Control	0.39	0.50	0.29
15-day cycling	0.42	0.54	0.29
10-day shed	0.67	0.85	0.39
Water Heater Dir. Control	0.14	0.18	0.10
Time-of-Use (TOU)	2.07	1.39	0.22
Interruptible	0.54	0.70	0.39
Swimming Pool Pump Interruptible	0.08	0.10	0.06
Swimming Pool Pump Timer	1.96	1.97	1.96
Real Time Pricing	NA	NA	NA
Agricultural			
Large Customer TOU (PA-2)	1.23	1.45	0.88
Small Customer TOU (PA-3)	0.95	1.09	0.73
Interruptible (PA-I)	1.55	1.92	0.51
Odd-Even Service (PA-R)	1.49	1.76	1.07
Commercial/Industrial			
Mandatory TOU A-23/A-22/A-21B	NA	NA	NA
A-23, Special Condition 10	10.68	12.06	0.42
A-22, Special Condition 10	3.14	3.55	0.38
Experimental TOU (A-20)	NA	NA	NA
Group Load Curtailment (GLC)	1.45	1.30	0.24
A-18B Interruptible	62.10	76.61	0.33
Small Commercial Interruptible	1.98	2.18	0.89
A-21A Optional TOU	9.38	5.76	0.19
A-7 Optional TOU	8.10	2.83	1.46
Real Time Pricing	NA	NA	NA
Commercial A/C Direct Control	0.76	0.98	0.48
General and Support Programs			
Community Electricity Management (CEMP)	3.28	6.20	0.79

The participant perspective was not explicitly determined.

NA means not available.

TABLE V-5 (Continued)

SUMMARY OF LOAD MANAGEMENT
PROGRAM COST-EFFECTIVENESS RESULTS
1984

Program Title	Unadjusted (Long-Term) Utility	Unadjusted (Long-Term) Society	Ratepayer
Residential			
A/C Direct Control	0.60	0.76	0.45
15-day cycling	0.66	0.84	0.46
10-day shed	1.05	1.33	0.61
Water Heater Dir. Control	0.18	0.23	0.13
Time-of-Use (TOU)	2.37	1.58	0.25
Interruptible	0.84	1.09	0.61
Swimming Pool Pump Interruptible	0.13	0.16	0.10
Swimming Pool Pump Timer	3.17	3.18	3.17
Real Time Pricing	NA	NA	NA
Agricultural			
Large Customer TOU (PA-2)	1.85	2.18	1.32
Small Customer TOU (PA-3)	1.42	1.63	1.10
Interruptible (PA-I)	2.52	3.11	0.83
Odd-Even Service (PA-R)	2.29	2.70	1.64
Commercial/Industrial			
Mandatory TOU A-23/A-22/A-21B	NA	NA	NA
A-23, Special Condition 10	16.72	18.87	0.66
A-22, Special Condition 10	4.92	5.55	0.60
Experimental TOU (A-20)	NA	NA	NA
Group Load Curtailment (GLC)	2.15	1.94	0.36
A-18B Interruptible	94.83	116.94	0.51
Small Commercial Interruptible	3.02	3.32	1.36
A-21A Optional TOU	12.45	7.65	0.25
A-7 Optional TOU	10.00	3.49	1.80
Real Time Pricing	NA	NA	NA
Commercial A/C Direct Control	1.17	1.50	0.73
General and Support Programs			
Community Electricity Management (CEMP)	4.03	7.58	0.97

The participant perspective was not explicitly determined.

NA means not available.

TABLE V-6

LOAD MANAGEMENT
COST-EFFECTIVENESS CALCULATION RESULTS
USING CPUC/CEC METHOD

	Perspectives[1/]		
	Society	Utility	Nonparticipant
Res. A/C 15-Day Cycling	.52	.41	.40
Res. A/C 5-Day Shed	1.23	.91	.89
Res. A/C 10-Day Shed	1.12	.78	.76
Res. W/H Cycling	.80	.67	.60
Res. TOU	1.45	.44	.37
Res. Interruptible	.95	.72	.70
Res. Swim.Pool Timer	6.41	6.04	5.98
Ag. Large Customer TOU	2.24	1.96	1.71
Ag. Interruptible	3.52	1.33	1.33
Ag. Odd-Even Rate	2.38	1.90	1.45
C/I A-23 SC 10	32.79	4.99	4.28
C/I A-22 SC 10	5.76	1.16	1.13
Group Load Curtailment	5.11	2.22	2.00
A-18B Interruptible	2.77	1.33	1.24
C/I Small Comm. Interr.	124.50	4.23	3.10
Coop. Elect. Mgt.	3.52	1.26	.72

1/ Staff assumes that all programs for which customers will volunteer are perceived as cost-effective by the participants.

While the cost-effectiveness of specific programs is addressed in more detail in later sections discussing the individual programs, some general observations can be made. The most notable is that only two load management programs meet the nonparticipant test when PG&E adjusts the avoided cost by its ERI. While we adopt PG&E's ERI methodology, as discussed in Section VI.A, we conclude that its original ERI adjustments, which were used in these calculations, were too pessimistic. Thus, PG&E's short term cost-effectiveness ratios tend to understate the benefits of load management.

Another observation in comparing PG&E's and staff's cost-effectiveness results is that staff's generally show more encouraging results than PG&E's. The staff witness was cross-examined regarding these differences, and explained some of the input assumptions he used. He also described his overall approach as follows (Tr. 7447):

> "What I did when I took a look at these programs, was I found that PG&E's numbers were quite low.
>
> "Their cost-effective numbers across the board are fairly low. What I did therefore was to make what I consider optimistic assumptions about how we might have looked at them with lower costs."

Based on the staff witness' own characterization of his input assumptions, we must conclude that staff's cost-effectiveness results tend to be overly optimistic. We are concerned also, as pointed out by PG&E, that the discrepancy between the relative magnitudes of the nonparticipant and utility benefit-cost ratios in the PG&E and staff analyses has not been adequately explained.

Because of the systematic biases in both PG&E's short-term ERI adjustments and staff's input assumptions, we tend to give more weight to PG&E's cost-effectiveness results from its long term perspective (no adjustment for system capacity conditions).

Six of the 19 programs for which cost-effectiveness is calculated meet the nonparticipant test under PG&E's long term assumptions. However, of the ones which fail this test, many have very low benefit-cost ratios (e.g., 0.25). Most programs meet the utility and societal cost-effectiveness tests; exceptions are noted in the later discussions of the individual programs.

There is a basic difference between the cost-effectiveness calculations for conservation and load management programs which concerns us, and that is the treatment of incentive payments and participant costs. Incentive payments made to customers for conservation activities such as replacing inefficient appliances or installing commercial conservation devices are treated as program costs, and are included in program revenue requirements and in all four cost-effectiveness tests. Any direct participant costs which are not offset by the incentive payments are also considered in the societal and participant tests.

On the other hand, any load management incentive payments which take the form of explicit and pre-established monthly bill reductions to the program participants are treated as transfer payments and are not included in the program revenue requirements or in the utility or societal cost-effectiveness calculations. Revenue shortfalls due to time-of-use (TOU) rates are treated similarly. Both incentive payments and TOU-caused revenue shortfalls are recovered through rate design from the customers in the customer class to which the program applies. (For example, the rates of all residential customers would be increased $2,310,000 to cover anticipated revenue shortfall due to bill reductions given to residential air-conditioner cycling participants.) Incentives for some load management programs are treated consistently with conservation expenditures; that is, they are included in utility revenue requirements.

PG&E estimates that incentives in 1984 for its proposed non-TOU load management programs would total $7.8 million. Of this amount, $4.5 million would be recovered through rate design. There is no explicit quantification in the record of the revenue shortfall due to TOU rates.

Since $4.5 million of incentive payments are not treated as program revenue requirements, they are not included in the utility or societal cost-effectiveness calculations. Neither do these tests include any other measure of costs incurred by participants. Thus, to the extent that participant costs (either direct economic costs such as increased labor costs or non-economic costs such as discomfort or inconvenience) exist, these tests produce overly optimistic measures of program cost-effectiveness.

Because of this understatement of costs in the utility and societal calculations for these programs, we tend to view the results with skepticism. As we noted in Section V.A on conservation cost-effectiveness, the nonparticipant test, while not binding, provides valuable insight into the impact on customers who for whatever reason do not participate in utility programs. We conclude that the nonparticipant test is even more important for those load management programs for which it is the only one, as currently constructed, that includes the cost of incentive payments.

As we did in D.82-12-055 for Edison, we instruct PG&E and staff, in PG&E's next rate case, to explore to what extent load management incentive payments should be included in revenue requirements instead of being treated as transfer payments. The related question of to what extent incentive payments, or some other measure of participants' costs, should be included in calculations of cost-effectiveness from the utility and societal viewpoints should also be addressed.

We realize that the incentive structure for TOU rates is more complex than that for other programs. The level of bill reduction depends upon whether the TOU rates are designed to be revenue neutral for average usage patterns, the usage pattern of the individual customer before entering the TOU program, and the extent to which usage is shifted as a result of TOU participation. The treatment of the TOU bill reduction in cost-effectiveness analyses should be addressed in the overall TOU program evaluation we are ordering today.

In Section V.A on conservation, we discussed why we don't rely exclusively upon the nonparticipant test to determine funding levels for specific programs. However, as for conservation, the generally poor performance of PG&E's load management programs in this regard is one of several factors leading to our decision to limit program expansion at this time.

As a final point, we note that PG&E did not present evidence regarding the load and energy reductions and other input assumptions for its cost-effectiveness analyses, nor did staff discuss the reasonableness of these assumptions. Since this is a crucial component of PG&E's and staff's cost-effectiveness analyses, we instruct PG&E and staff to present testimony on this matter in PG&E's next general rate case.

4. Electric Load Management

For each load management program discussed below, the heading provides PG&E's 1984 request, staff's recommendation, and the adopted expenditure level, all in 1984 dollars.

a. Residential Load Management Program

PG&E proposes funding for five residential load management programs with increases of about 30% over expenditures planned in 1983. Most of the increase would be for expansion of the air conditioner (A/C) direct control program and residential TOU rate program.

(1) Air Conditioner Direct Control - $5,608,000 - $2,930,000 - $3,376,000

This program provides financial incentives to customers who voluntarily allow their air conditioners to be cycled by direct utility control. Several cycling strategies have been developed. PG&E plans to expand the program by installing 6,500 cycling units in each of the years 1984 and 1985. The number of proposed installations was reduced from 20,000 each year during the rate case. PG&E proposes funding of $5.6 million in 1984 compared to staff's funding recommendation of $2.9 million.

The A/C Direct Control program has received favorable customer response as gauged by the participation of about 64,000 residential customers as of 1982. By the end of 1983 PG&E expects to install 14,000 more cyclers.

This program is recognized by the CEC as a viable load management program which should be pursued. In its order dated June 1, 1983 the CEC ordered PG&E to "...install up to 13,000 central air conditioner cyclers in 1984 and 1985." PG&E was further ordered to submit a specific plan to do so at least 30 days prior to initiating any new demonstrations in 1984 and 1985. Moreover, prior to such initiation, PG&E must develop and implement a program for reducing program costs. The CEC order directed PG&E to make certain modifications to its cycling program, such as concentrating on hotter climate zones, and made other cost-cutting suggestions:

> "If any of the 14,000 cyclers purchased in 1983 are not already committed to experiments as of June 1, 1983, they should be redirected to the experimental targets cited above, with first priority going to selective marketing to new high use customers. Otherwise, the cyclers for new experiments should be obtained in the most cost-effective manner possible and to include explicit consideration of the removal of control switches from current participants (as indicated in these recommendations."

Since these modifications will require less than the requested funding, the CEC proposes to establish a balancing account which will allow the refund of unspent program funds.

PG&E's analysis shows that the program is cost-effective in the long term from the utility and societal perspectives only if the 10-day shedding option is adopted. The 5-day shedding option and the 15-day cycling option fail all cost-effectiveness tests.

Staff finds the 5-day and 10-day options cost-effective from the societal perspective only. Staff's recommended reduction in the level of funding results from effectively terminating the cycling program and retaining load shedding only. Staff also adjusts PG&E's request by $720,000 since this amount was not justified.

We agree with the CEC that the load shedding option only should be pursued. The cycling option is clearly not cost-effective to anyone and should not be continued. While allowing the requested program expansion, we have considered the order of the CEC to reduce program costs.

The record does not reveal how many of the 14,000 cyclers originally planned to be installed during 1983 have been redirected to meeting the 1984 and 1985 goals, nor to what extent PG&E will remove control switches from current participants to reduce the number of new switches which must be purchased. However, late-filed Exhibit 263 indicates that PG&E plans $1,724,000 in capital expenditures for this program between September and December of this year. We assume that these expenditures, and indeed all cycler purchases since June 1, 1983, have been made in accordance with CEC directives, and thus that they reduce 1984 program expenditure requirements.

We will authorize the A/C Direct Control program at the requested level with the above modification to recognize cycler purchases in the last four months of 1983. The conditions set forth by the CEC raise the prospect of even further reductions in program costs. While we will not adopt the CEC's recommendation of a balancing account to return unspent program authorizations, we do find it reasonable to restrict expenditure of all funds authorized for this program to the A/C program. Accordingly, any unspent funds remaining at the end of 1984 will be carried over with interest to fund the 1985 A/C program. The treatment of any unspent funds remaining in 1985 will be addressed in PG&E's next general rate case.

(2) Water Heater Direct Control - <u>$190,000; $0; $164,000</u>

PG&E requests funding to maintain its existing water heater direct control program and to remove equipment as customers drop out of the program. PG&E had originally proposed to add 3,740 customers to the program in 1984, but now plans to halt program expansion.

This program fails to meet any of the cost-effectiveness tests in the short term or long term, and we agree that the program should be discontinued. We will approve the expense component of the requested funding to allow the orderly termination of this program in 1984. However, we will not authorize collection of any incentive payments through rate design. PG&E should cease operation of the existing program, and should remove all equipment during the test year.

(3) Residential Time-of-Use (TOU) - <u>$11,460; $1,325,000; $3,000,000</u>

D.82-12-113 dated December 22, 1982 authorized PG&E to install 21,000 residential time-of-use meters by the end of 1983. For 1984 and 1985 PG&E requests $11.5 million and $12.9 million, respectively, to install another 30,000 devices in each of the two years.

Under PG&E's analysis the program passes the utility and societal tests both in the short and long terms. Under staff's analysis the program passes only the societal test. PG&E wishes to expand the program in order to provide customers with a wider range of options.

The ECB staff recommends that the TOU program be treated as an experiment during the next two years in order to allow an opportunity to evaluate carefully the impact of this program. ECB proposes that no more than 5,000 meters be installed, including existing meters. ECB staff's chief criticism of the current program is that it is impossible to ascertain whether the program has caused load shifting from peak to off-peak periods and if so, whether such load shifting is cost-effective. ECB staff points out that PG&E has failed to study the load characteristics of participants prior to the program in order to compare their behavior before and during the program. Staff points out that participants may realize major rate benefits from just being on the current TOU schedule without shifting load. ECB staff concludes that PG&E should conduct controlled studies of the program in order to determine its success and to submit specific data to the staff to permit independent evaluation (Exhibit 139).

The Rate Design and Economics Branch (RDE) staff supports the TOU program, arguing that because it provides customers with accurate economic signals of the cost of their energy usage during various periods of the day. By reflecting the utility's cost of producing electricity, resources are allocated more efficiently. The RDE staff did not make any analysis or recommendations concerning which customers should bear the costs of implementing and operating this program.

The Local Government Commission (LGC) and Contra Costa County both enthusiastically support the program and urge continued expansion at a rapid pace. LGC sponsored the testimony of Dr. Jan Paul Acton in support of the program. Dr. Acton summarized load shifting data from a TOU experimental program in Los Angeles and relies in part on this data in concluding that the PG&E program is effective. In his view the PG&E program results in families shifting their use of energy in the peak period from 19% to about 13% total usage.

Dr. Acton proposed a TOU rate schedule that is revenue neutral in response to concerns raised by ECB staff. This means that customers with "average" usage patterns who choose to participate in the TOU schedule will only receive a benefit if they shift load. Otherwise, the rate levels will be the same as if they did not participate.

LGC further asserts that the TOU program not only induces load shifting out of peak periods but also satisfies other objectives such as cost-effectiveness, efficient use of resources, providing accurate price signals to customers, and providing rate options to large users of electricity.

TURN opposes the continuation of the TOU program and urges that the Commission terminate it. In TURN's view, the program has allowed large residential users, who are typically better off economically, to reduce their energy bills without shifting load to the off-peak period. TURN also argues the program is not cost-effective and that it results in large subsidies from nonparticipating residential customers with no offsetting benefits. Specifically, TURN questions why additional financial incentives (or participation incentives) must be built into the TOU rate when the rate is offered as one of many options to promote customer choice.

TURN also believes that the program unfairly benefits the wealthy at the expense of the middle class and poor. TURN cites PG&E's data which shows the median household income of TOU participants is $46,135 per year, and that the majority of participation is from customers at this income level or higher in Contra Costa County.

As an alternative, TURN recommends the adoption of the ECB staff witness proposal that PG&E conduct a carefully controlled experiment much like Southern California Edison's Demand Subscription.

Service (DSS) program. Specifically, TURN reiterates the necessity to collect data before and after participation in the TOU rate in order to evaluate the effectiveness of the TOU program. TURN also suggests that the peak periods be redefined for summer and winter. Specifically, during the winter TOU customers are improperly billed at off-peak rates for at least two hours of the winter on-peak period.

Time-of-use programs in general, and the residential TOU program in particular, are the most controversial load management programs. Unlike interruptible or curtailable programs, TOU programs do not give the utility direct control over load. As a result it is difficult to measure accurately the overall effectiveness of these programs.

We recognize that the TOU program has given participants more accurate economic signals concerning the relative cost of their electricity usage during various periods of the day. However, we agree with LGC that, in the future, the TOU rates should be designed to be revenue neutral to residential customers with "average" usage patterns. The incremental metering costs associated with TOU meters should also be recognized in the tariff design. This should increase the cost-effectiveness of the program. TURN's point that incentives should not be necessary and are not appropriate to induce customers to participate in rate options is well taken.

We are also concerned with the accelerated pace at which PG&E proposes to expand the residential TOU program. Our concerns are two-fold. First, PG&E has not performed a detailed controlled analysis to ascertain the overall effectiveness of this program. We agree with our ECB staff that in order to evaluate whether this program is successful in shifting load and thus whether it is cost-effective from any perspective other than the participant's, it is necessary to set up a carefully controlled experiment to determine the load characteristics of customers before and after participation in the program. While we acknowledge that some load shifting has probably occurred under this program we cannot determine how much in order to determine the overall cost-effectiveness of the program. We are also concerned that evaluation be made of the effectiveness of the TOU option in different climate zones in PG&E's territory.

In view of the above and mindful of staff witness Ahern's policy perspective, we deem it prudent not to allow widespread expansion of this program until we can determine whether it achieves load shifting on a cost-effective basis to the utility, to society, and to the nonparticipant. The next two years fortunately provide us with a unique opportunity to test the results of the residential TOU program and to make changes where possible to improve the program's cost-effectiveness.

We authorize the addition of up to 5,000 TOU participants during the next two years within the experimental guidelines proposed by staff. These new participants should be chosen to obtain representative data from each of the relevant climatic zones. This will allow collection of experimental data in a manner to allow a thorough evaluation of the program.

Cost-cutting measures similar to those suggested by the CEC for the A/C Direct Control program are also in order for this TOU program expansion. If any of the TOU meters purchased during 1983 are not already installed as of the effective date of this order, they should be redirected toward the experimental goal established by this decision. Further, any meters removed from current participants due to drop-out or other reasons should similarly be applied toward this goal.

There is no explicit data in the record regarding the cost of the program modifications we are making. However, a generous estimate of costs is $3 million for each of 1984 and 1985.

Due to the uncertainty regarding the needed expenditure levels, we will treat residential TOU funds as we do A/C Direct Control authorizations. If program expenses in 1984 are less than the authorized amount, we expect PG&E to carry forward unspent monies (with interest) to supplement 1985 expenses for this program. The treatment of any unspent 1985 program authorizations should be addressed in PG&E's next general rate case.

In Appendix A we set forth the reporting requirements which we will require of PG&E to permit independent staff analysis of this program.

(4) Swimming Pool Pump Timer Program - $413,000; $386,000; $384,000

PG&E requests funding to expand this successful program in 1984. Staff supports the proposal. The difference in funding between PG&E and staff is due to reliance on different escalation rates.

This program appears cost-effective from all perspectives and therefore meets the policy objectives discussed by Ahern. We will authorize its continuation at funding levels that reflect our adopted escalation rates.

b. Agricultural Load Management Programs

PG&E proposes substantial increases in funding for agricultural load management programs in 1984. For the four programs for which it requests funding, PG&E's 1984 proposed budget is 230% of the 1983 budget. This request reflects PG&E's view that, as a matter of equity, greater customer options should be provided to all classes of customers, including agricultural.

(1) Large Customer Time-of-Use (PA-2) - $5,133,000; $3,188,000; $1,000,000

PG&E proposes to install 3,000 meters in 1984 in its PA-2 TOU program. More than 10,000 agricultural customers are expected to participate in this program by the end of 1983. PG&E's proposed expenditure in 1984 is nearly double what it spent in 1983.

Under the PA-2 program, customers with maximum demands greater than 35 kW may participate. The PA-2 rate includes a monthly demand charge.

Under PG&E's cost-effectiveness analysis the program satisfies the utility and societal tests in the short term and all tests in the long term. In the short term, however, the program does not meet PG&E's nonparticipant test. Staff supports the program but would cut funding as part of its overall reductions in total load management funding.

While this large agricultural TOU program appears promising in the long term, we do not believe that it should be expanded at this time, consistent with out adopted policy of delaying large-scale expansion of load management programs until the time additional capacity is needed. We authorize $1 million in 1984 to allow continued analysis of the program at existing levels.

Our staff points out that by D.82-12-113 dated December 22, 1982 the Commission ordered a $6.3 million refund to be applied to customers on schedules PA-1 and PA-2X. While the rates were in fact reduced, the Commission did not make a corresponding reduction in total jurisdictional revenue requirements. Staff believes that PG&E could have technically claimed the $6.3 million rate reduction under the ERAM mechanism. Staff therefore recommends that the Commission reduce jurisdictional revenue requirements by $6.3 million at this time.

Since our decision in December 1982, PG&E has undergone an ERAM adjustment. We will require PG&E in its next ERAM proceeding to show whether or not the $6.3 million refund was treated correctly and to adjust ERAM if necessary.

(2) Small Customer Time-of-Use (PA-3) -
$1,871,000; $0; $500,000

PG&E requests installation of 2,000 TOU meters for 1984. This program is available to those customers with maximum demands between 10 and 35 kW.

Like the PA-2 program, PG&E's analysis shows that the PA-3 program will be cost-effective for the short term under the utility and societal tests, and nearly cost-effective under the nonparticipant test. In the long term, the program is expected to be cost-effective under all tests. Staff has performed no cost-effectiveness analysis of this program.

RDE staff supports the program. ECB staff opposes it based on its belief that the rates are not effective in shifting load from on-peak to off-peak, and that the low demand of these customers does not provide ample incentive for them to shift their load.

This rate schedule was proposed by a PG&E advice letter filed February 9, 1983. It, therefore, can be characterized as a new experimental program. Consistent with Ahern's policy perspective outlined above, we are reluctant to authorize funding for expansion of new experimental programs until such time that additional capacity is needed. We will authorize funding of $500,000 so that PG&E can use the existing meters to perform further experimentation and report on the effectiveness of this program in inducing load shifting. We note that many of the issues regarding measurement of the cost-effectiveness of a residential TOU program are also relevant for the agricultural program.

PG&E and staff shall cooperatively develop reporting requirements for this experiment.

(3) Interruptible - $355,000;
$296,000; $329,000

PG&E proposes to establish a new experimental program to test direct radio control of agricultural customer loads. Pumping loads will be shed for up to six hours on those summer weekdays that PG&E requires load relief.

PG&E expects this program to be cost-effective to the utility and society both in the short and long terms, and to be nearly cost-effective to the nonparticipant in the long term.

Unlike the TOU program, this program allows the utility direct control over load. Accordingly, the utility can more easily obtain measurable data on the amount of capacity saved as a result of the program. We will authorize the requested funding for 1984, adjusted for escalation, to permit a thorough evaluation of the experiment. Efforts should be made to increase the program's cost-effectiveness to the nonparticipant.

(4) Odd-Even Service - $1,160,000; $1,010,000; $1,075,000

PG&E proposes this new experiment which would charge agricultural customers higher on-peak prices on alternate weekdays. Customer with demands greater than 35 kW have an incentive to reduce electricity consumption on odd- or even-numbered days.

Under both the staff and company analyses, the program is expected to be cost-effective from all perspectives in the short and long terms. We authorize PG&E's requested funding, adjusted for our adopted escalation rates.

c. Commercial/Industrial Load Management Programs

PG&E requests $8.3 million in funding in 1984 for ten programs to provide time-of-use, interruptible, and curtailment rate options to commercial and industrial users. This request represents about a 65% increase over expected expenditure levels for 1983.

(1) Mandatory TOU A-23/A-22/A-21B $150,000; $28,000; $144,000

PG&E requests continuation of the phased implementation and analysis of mandatory time-of-use rates for commercial and industrial customers with demands greater than 500 kW. PG&E expects to add another 60 TOU meters in 1984 to the 2,200 meters which PG&E plans to install by the end of 1983.

There is no data available on the cost-effectiveness of this program.

Staff proposes funding at $28,000 for 1984 on the basis that this program has not been effective in causing load shifting. In staff's opinion, the Commission in prior decisions expected load shifting of 5 to 10% under each of these schedules which staff contends has not occurred. In staff's view, the absence of effective load shifting has resulted in an overcollection in revenue by the utility. Staff proposes further evaluation before the program is expanded.

Although it is true that in our prior decisions we contemplated that certain levels of load shifting would occur, we did not set specific goals which the utility was required to achieve. Instead, we anticipated an expected range of load shifting under these rate schedules and authorized revenues accordingly. While it is possible that the utility overcollected revenues because the anticipated load shifting may not have occurred, we cannot with confidence ascertain as much from this record. Moreover, we observe that under the ERAM mechanism, adopted in D.93887 for PG&E to be effective January 1, 1982, PG&E will record and refund any overcollected revenue realized.

We nevertheless find staff's observations about the effectiveness of this and other TOU programs compelling. In this case, PG&E has substantially reduced the level of funding for this program from 1983 levels. We will permit PG&E to continue this program but, like all other TOU programs, will require PG&E to evaluate carefully the results in accordance with the reporting requirements set forth in Appendix A.

(2) A-23, Special Condition 10 -
$300,000; $99,000; $278,000
A-22, Special Condition 10 -
$167,000; $41,000; $154,000

These experiments provide voluntary curtailable options for the two largest groups of commercial and industrial customers. Participants bear the cost of equipment at their facilities which is offset by monetary rate incentives.

According to PG&E, both of these programs will satisfy the utility and societal cost-effectiveness tests in the short and long terms.

Staff proposes substantial cuts in funding, again on the basis that these programs have not demonstrated any load shifting. We agree with PG&E, however, that curtailment options are not designed to induce load shifting but rather load reduction when PG&E requires load relief.

We will authorize funding for these two programs at the requested level for 1984, adjusted for escalation. However, we expect PG&E to continually reevaluate the cost-effectiveness of these experiments, and particularly to take reasonable steps to improve their cost-effectiveness from the nonparticipant's perspective.

(3) Group Load Curtailment - $3,607,000; $1,806,000; $2,000,000

This program is similar to the ones described above. Under this schedule a group of large commercial and industrial users pool their usage to qualify for a lower rate. In return PG&E can require the group to reduce its load to a previously agreed level for up to six hours.

PG&E expects to add two more groups in 1984 at a cost of $3.6 million. Staff supports continuation of the program.

PG&E calculates that this program is cost-effective to the utility and society both in the short and long terms, but that its benefit-cost ratio for nonparticipants is very low (0.24-0.36). This is another direct control-type program which can produce readily quantifiable benefits. However, PG&E's low nonparticipant benefit-cost ratios are disturbing. We will fund this program at $2 million to allow continuation of this program with the existing participants, but no expansion in 1984. PG&E should make a particular effort to improve the cost-effectiveness of this program to nonparticipants.

(4) A-18B Interruptible - $130,000;
$60,000; $119,000
Small Commercial Interruptible -
$99,000; $36,000; $90,000

The A-18B interruptible program allows the utility to interrupt customer load by reducing it to a predetermined level when the utility faces an underfrequency or undervoltage emergency. In return, participants receive a bill reduction. PG&E proposes to add two customers in 1984.

The small commercial interruptible program is a new, experimental program for those customers who are ineligible to participate in the A-18B program. PG&E requests funding to review and analyze results of a 1983 experiment. Any additional capital installations would be delayed until 1985.

Under the utility's analysis both programs are cost-effective in the short and long terms to the utility and society. However, the cost-effectiveness to the nonparticipant of the A-18 B program is low (0.33 to 0.51).

Staff supports both programs. We will authorize funding for both of these programs at the levels requested for 1984 adjusted for escalation. Like the curtailment programs, PG&E should attempt to increase the cost-effectiveness of these programs to nonparticipants.

(5) A-21A Optional TOU -
$1,312,000; $0; $440,000
A-7 Optional TOU -
$1,591,000; $0; $560,000

These are voluntary time-of-use programs for customers with demands below 500 kW. The ECB staff opposes funding for these programs while the RDE staff supports them. ECB staff's objections are generic to all of the TOU programs and will not be repeated.

PG&E shows the A-21A program is cost-effective to the utility and society both in the short and long terms. The A-7 program is shown to be cost-effective from all perspectives. Staff made no cost-effectiveness analysis.

Both of these programs are new and thus untested. We note that PG&E plans to conduct an ambitious program in 1984 by installing 1,000 devices for the A-21A program and 2,000 devices for the A-7 program. We do not find that such large expenditures are prudent at this time. We will approve funding of $1,000,000 to allow a carefully controlled experiment. We expect PG&E to design this experiment to collect usage data from potential participants before they are put on TOU rates and to report program design and results to the staff consistent with our discussion on the residential TOU program and the reporting requirements in Appendix A.

(6) Real Time Pricing - $438,000; $0; $419,000

In cooperation with the Massachusetts Institute of Technology (MIT), PG&E proposes to conduct an experiment in real time pricing with 10 participants. Under this program participants will be given a daily price schedule by hour of energy usage, 24 hours in advance. Staff argues that the study should be done in-house.

We are interested in having PG&E pursue this experiment with MIT in light of MIT's active involvement in real time pricing experiments. We therefore will authorize the requested funding in 1984, adjusted for escalation.

(7) Commercial A/C Direct Control - $498,000; $0; $462,000

PG&E initially requested $798,000 to add 180 new participants to this program in 1984. By the end of 1983 PG&E expects to have 1,160 participants. PG&E now plans to delay further program expansion until 1985 and requests $498,000 in 1984 to review and analyze results of the 1983 test program.

Under PG&E's analysis, the program is not cost-effective under any of the tests in the short term. In the long term the program is expected to be cost-effective to the utility and society.

Staff opposes continuation of this program in the belief that it is ineffective. Staff's objections are similar to those made against the residential A/C Direct Control program.

Given the experimental nature of this program, and considering the program's lack of cost-effectiveness in the short term, we are reluctant to expand the program even in 1985. We believe that instead of expanding this program, PG&E should use the next two years as an opportunity to evaluate carefully the program's cost-effectiveness, and will authorize the requested funds, adjusted for inflation, for this purpose in 1984.

d. General and Support Programs - $17,678,000; $6,084,000; $12,191,000

PG&E requests an increase of 135% from 1983 expenditure levels for 10 general and support programs. Most of these programs are for acquisition and evaluation of load data and metering systems. About $3.2 million of the request would fund administrative functions.

The Community Electricity Management Program (CEMP) for which $3.5 million is requested in 1984 is an informational-type program. Under this program PG&E works with communities to publicize methods for reducing peak electricity usage. Participating communities are rewarded financially. The CEMP also assists in recruiting participants for the other load management programs. PG&E expects to add three more cities in 1984.

The ECB staff believes that this is essentially an advertising program which PG&E has not shown to be effective. Staff believes that the activities of this program should be carried out by PG&E's own personnel instead of community volunteers. Staff recommends a budget of about $1.1 million.

According to PG&E this program is experimental. PG&E filed a report analyzing this program in 1980. Before we authorize expansion of this program we will require an updated report. This is consistent with the staff's policy to assure that experimental programs are clearly successful before continuing or expanding them. We will authorize $1 million for this program.

PG&E requests about $5.7 million to do end-use load analysis, metering of small power producers, and PURPA and class load analysis. The proposed funding level is about 40% greater than expenditures in 1983. Most of the increases are for end-use analysis.

Staff supports these programs but recommends funding reductions to reflect what staff believes are more likely levels of activity, given PG&E's past experience.

We view load analysis as essential to any final determination of the cost-effectiveness of a given program. In fact, many of the reductions in funding proposed by the ECB staff, and many of the reductions we have adopted, reflect the view that the load characteristics of participants of these programs must be evaluated in order to conclude whether or not a program is effective. We, therefore, will authorize funding for load analysis progams at the requested levels in 1984, reduced to reflect adopted escalation rates.

For the same reasons, we will authorize PG&E to fund its data acquisition and analysis program, the demand control center, and the metering systems evaluation program. Consistent with staff's recommendations, we fund the marginal cost/economic analysis effort through the Conservation budget.

Lastly, PG&E requests about $3.2 million to fund administrative functions. Since we have made a number of reductions in proposed expenditures, we find that a similar reduction is warranted for administrative functions. We, therefore, will authorize funding for this activity in proportion to the level of program funding we authorize.

5. Gas Load Management - $2,910,000; 1,673,000; $500,000

PG&E requests $2.9 million to fund gas load management programs. These programs are for data collection and analysis, and parallel the general and support programs requested for electric load management. The majority of the expenditures are for operating expense.

PG&E spend $455,000 on gas load management in 1982 and plans to spend only $416,000 during 1983. PG&E has presented no justification for increasing its budget in 1984. Further, staff has recommended transferring the marginal cost analysis program to the conservation area, and we have adopted this recommendation. We will fund the remaining gas load management activities at $500,000.

6. Other Issues

a. Staff Rate of Return Penalty

ECB staff proposes a penalty of 15 to 29 basis points on PG&E's rate of return on equity for PG&E's alleged failure to achieve demand reductions or achieve cost-effective load management programs in accordance with the Commission's expectations and the utility's own projections. Staff proposes an additional 22 basis point penalty to compensate for alleged overcollections from customers under the time-of-use schedules.

We have already indicated that in prior decisions we did not specify goals or targets of demand reduction which PG&E was required to meet with various load management programs. Based on the information available at the time we simply indicated our expectations of the level of demand reduction which could be achieved under these programs. PG&E asserted that start-up problems delayed program implementation. This was not refuted by staff. We do not wish to send signals to PG&E to spend money simply to show it can. We, therefore, agree with PG&E that penalties for failure to achieve these expectations are not justified.

We do expect programs to be as cost-effective as possible. While we do not believe that penalties are in order at this time to ensure that PG&E implement cost-effective programs, we put PG&E on notice that it should terminate programs authorized in this decision if they prove to be clearly noncost-effective.

Regarding alleged overcollections under TOU rates, we have already pointed out that ERAM will capture these.

b. Reporting Requirements

Staff recommends that PG&E record and measure the results of its load management programs in a manner which would allow determination of their effectiveness. In the area of load analysis staff believes that PG&E should set up a detailed tracking system that would keep time-differentiated records of customer consumption and demand by tariff schedule, and which would account for all rate changes that occur. We will adopt this recommendation.

For determining the effectiveness of time-of-use rates, both residential and nonresidential, staff recommends the collection of data on the load characteristics of the class for which these rates are offered. Staff's proposal is contained in Appendix A. In addition staff recommends that PG&E provide tables showing the expected effect of proposed rates on sales and revenues at the end of 1983, 1984, 1985.

We find staff's reporting requirements reasonable and will adopt them. With the type of data to be collected, we can better evaluate the overall effectiveness of specific time-of-use programs. We expect PG&E to cooperate completely in providing the information the staff requires to make its independent analysis.

c. Disposition of Unspent Load Management Funds

This issue has been resolved in the Conservation section of this decision.

C. <u>Research, Development, and Demonstration</u>

PG&E has requested $40.3 million in 1984 and $49.4 million in 1985 for funding of its research, development and demonstration (RD&D) programs.[7] PG&E has identified six major research areas which encompass a total of 32 programs and which are described in Exhibits 17 and 17a. These programs are composed of 150 projects. Included in the total amounts requested are $14.5 million in 1984 and $17 million in 1985 for contributions to research organizations such as the Electric Power Research Institute (EPRI) and Gas Research Institute (GRI). Additional contributions to EPRI are noted in the descriptions of specific programs.

PG&E's request is presented in Table 1 of Exhibit 17-A. Of this amount, $16.1 million is for basic research, $2.5 million is for administration and maintenance of a corporate research laboratory, and $14.5 million is for contributions to research organizations. The balance of $7.1 million is directed towards the Carrisa Plains Project and the Cheng Cycle Demonstration Program.

Staff recommends that the Commission fund $29.8 million of the requested amount for 1984. Both staff and PG&E evaluated and ranked the programs in accordance with D.82-12-005 in OII 82-08-01. Staff, however, eliminated funding for programs which are currently being funded by other entities, which are more appropriately funded by natioal research organizations, or which should be capitalized instead of expensed. In addition, staff eliminated all funding and contributions for nuclear-related projects.

Staff's methodology and analysis for review of PG&E's RD&D request are continued in Exhibit 149. Table 3 of Exhibit 149 summarizes the staff's adjustments.

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7 The original request was for $67.3 million. PG&E's revised request is in 1981 dollars. In 1984 dollars, staff calculates PG&E's requested amount for 1984 as $51.4 million.

We will review each of the six research areas and discuss where adjustments, if any, are appropriate.

Research Area I encompasses programs which are designed to improve efficiency and reliability of generation, transmission, distribution and support facilities. In 1984 staff recommends removal of $300,000 from the $4.1 million requested by PG&E. These adjustments largely result from the fact that other entities are conducting research for many of these projects. We observe in general that most of the projects discussed under this research area are generic to the utility industry and could be funded by utility-supported research organizations. We find the staff's adjustments to be reasonable.

For the same reasons cited by our staff for its recommended adjustments we will make a number of additional adjustments in this research area. Specifically, the Gas Facility Integrity and Reliability Program ($100,000) and the Gas Processing and Odorization Program ($39,000) are activities generic to the gas utility industry. These activities are likely being performed by national gas research organizations such as GRI. In our view funding by such organizations is more appropriate. Accordingly, we will remove specific funding for the above activities.

We will make a further adjustment in this research area to eliminate the program of Installation and Service Cost Reductions ($50,000) under the area of Electric Transport. The program is designed to review existing facilities for security, reliability, and efficiency of maintenance and repair. In our view this activity is not RD&D, and not properly funded as such.

Research Area II funds the development of alternative energy technologies, such as wind, solar, and geothermal, and new coal and nuclear technologies. A total of $6.1 million is requested for 1984. Staff would reduce the requested amount by $885,000. A large portion of the reduction is for the Molton-Carbonate Fuel Cell project. Staff observes that Southern California Edison has abandoned a similar project and that EPRI is currently performing a demonstration of this technology which is experiencing problems. Other reductions are made to eliminate duplicative funding of similar projects conducted either by PG&E or by other utilities. We find staff's reductions to be reasonable.

Moreover, other projects in this research area for which PG&E is requesting ratepayer funding concern us. First, PG&E proposes to expense the Photovoltaic Cell Module demonstration project ($300,000) built by Westinghouse. Since this is a demonstration project which may become used and useful to the utility, the costs should be capitalized in accordance with our guidelines in D.82-12-005.

Secondly, PG&E requests $150,000 in 1984 to fund research into fusion technology. In our view this research is of national benefit and provides no unique benefits to PG&E. Indeed, staff assigns this program low priority. We believe this research should be funded through PG&E's contributions to research organizations. In fact PG&E acknowledges that certain studies are currently being coordinated through EPRI. We therefore will not authorize funding in this area.

Thirdly, PG&E requests $50,000 to "establish minimal involvement with organizations already active in hot water geothermal technology...." PG&E has no proven hot water geothermal sites in its service territory but indicates that funding for this activity will "keep its options open." We are not convinced that PG&E derives any specific benefits from this program that could not be derived from participation in EPRI or other research organizations. We therefore will not authorize the requested funding.

Lastly, PG&E seeks $50,000 to "monitor, evaluate and pursue other nonfuel systems." Other than stating that these systems include various unconventional systems for solar, wind, hydro, etc. which apparently differ from projects previously described, there is no indication what technologies are contemplated. PG&E also indicates that the requested amount allows PG&E to establish contacts and monitor developments to obtain design and evaluation information, develop project plans for development of promising options by PG&E, or alternatively by participation with other utilities, sponsors, or developers. This description is vague and appears to duplicate efforts provided by research organizations like EPRI. We therefore will not authorize funding for this activity.

PG&E requests $535,000 in 1984 to fund Research Area III defined as research to reduce growth in energy demand. Staff has proposed no reductions to this request. We discuss the requested funding in the sections on load management and conservation.

Research Area IV funds methods to improve environmental quality and safety. PG&E requests $5.4 million in 1984; staff reduces the request to $4.2 million. A major reduction is for research on acid rain which is currently being conducted by other organizations and by the State Air Resources Board. Other reductions are made to eliminate funding of research which is being done by EPRI and others.

As part of its request in this area, PG&E seeks $303,000 to fund four "advisors" to provide ongoing long-and-short range advice in their respective areas of air, water, land use, and radiation protection to the company's line departments. (Exhibit 139, Appendix B, p. C-62.) In our view funding of four "advisors" for this purpose is duplicative of environmental studies required for individual projects which are also funded by ratepayers. We find no justification for ratepayers funding of long-range environmental studies which have no relation to either a specific power plant project, transmission line or other facility. We therefore will reduce PG&E's request by this amount in addition to the reductions made by staff.

Similarly, PG&E seeks $330,000 in funding for "Terrestrial Methods," which includes "study of deer losses in canals, bald eagle habits, and the relation of riparian vegetation to stream flow." Although not clear, it appears that these studies are in connection with hydro projects. PG&E has indicated that the studies in some cases relate to specific projects and in others do not. We are reluctant to have ratepayers fund generic environmental studies, and find it reasonable to reduce the requested funding amount by one-half.

Research Area V funds contributions to research organizations and PG&E-employee salaries for conducting general research. PG&E requests $17 million, mostly for EPRI and GRI. Staff eliminates all funding or contributions for nuclear-related projects. Another $500,000 reduction in contributions is made for lack of justification. The total adjustment recommended by staff is $1.08 million. We find staff's adjustment reasonable.

Staff would also adjust the requested contributions to EPRI and GRI to reflect actual billings available in October 1983. This is consistent with our prior decisions, and will be adopted.

Although PG&E places contributions to EPRI and GRI in Research Area V, we observe that a number of programs included in Areas II-IV are co-funded with EPRI or GRI in addition to PG&E's general contributions. Specifically, the Ammonia Cooling Demonstration at Kern Power Plant is funded in part by EPRI. PG&E is contributing $430,000 to this project in 1984. Similarly, the Phosphoric Acid Fuel Cells Program for which $241,000 is requested in 1984 is part of a larger effort managed by GRI. The Coal Pyrolysis Plant Program ($50,000) and the Solano Wind Turbine facility ($450,000) are also EPRI-sponsored projects. We will authorize the requested funding. However, in future rate cases we expect PG&E to explain more adequately why PG&E's ratepayers should be asked to make additional contributions beyond the substantial dues PG&E pays yearly to EPRI and GRI for specific projects.

Under the category of general research, which funds employee salaries, we find a number of individual projects for which additional salary requests are made primarily to participate in EPRI workshops, task forces or user group activities. A total of up to $285,000 relates to such participation. There is no explanation as to why additional funding for employee salaries is necessary. We therefore will reduce the requested funding by one-third to avoid double funding of employees through administrative and general accounts and RD&D accounts.

In sum we authorize $30 million in 1984 for RD&D as shown in Table V-7. This amount reflects the reductions we have already made. Even with these adjustments, PG&E's request compares favorably with 1983 funding levels. We believe this amount is sufficient for PG&E to aggressively pursue RD&D.

TABLE V-7

Electric and Gas
RD&D Expenditures Test Year 1984
1981 Dollars (000)

	PG&E Request	Staff Recommendation	Adopted
Area I Efficiency	$ 4,150	$ 3,850	$ 3,661
Area II Diversification	6,100	5,215	4,569
Area III Demand Reduction	535	535	535
Area IV Environmental	5,400	4,226	3,593
Area V General and Contributions	17,000	16,020	17,644[2]
Area VI Demonstration	7,100	7,100[1]	0
Total	40,285	36,946	30,002[3]

1 Staff recommended capitalization of all demonstration projects.

2 Contributions totaling $15,044,000 is in 1984 dollars.

3 The adopted amount in 1984 dollars is $32,305,000. Of this amount $3,857,000 is for gas and $28,448,000 is for electric.

In addition, we direct PG&E to comply with staff's recommendations that PG&E's future RD&D filings and April 15 annual report: (1) be in the format shown in Appendix D of staff's Exhibit 149 on RD&D, and (2) include an estimate of quantifiable benefits, e.g., potential cost savings to the utility or its ratepayers accruing as a result of increased systemic efficiencies, demand reductions and the development of new energy technologies, consistent with D.82-12-005 (p. 2, Exhibit 149).

D. Cogeneration and Other Small Power Resources

No issues concerning cogeneration expenses were raised in this proceeding. We will authorize funding at the level set forth in our discussion of Account 930.2.

After reviewing and monitoring PG&E's activities, the staff concludes that PG&E's overall performance in this area is satisfactory. This is reflected in the staff Exhibit 144 excerpt below:

> "General recommendations to the Commission regarding the future course of PG&E's program for purchasing electricity developed by cogenerators and other small power QFs were made by the Utilities Division Director, W. R. Ahern, in his long-range planning exhibit. Mr. Ahern noted the 'Utilities Division staff now feel that PG&E has been making adequate progress toward implementing the Commission's and the Energy Commission's policies encouraging the development, by third-parties, of cogeneration and small power production from biomass, hydropower, solar power and wind sources'. This observation was based on PG&E's reports to staff that it has about 1,500 megawatts (248 projects) of QF power committed, about one-half as cogeneration and the rest from biomass, solid waste, wind and hydroelectric power, see Table 1. In total, these accomplishments appeared then, (late February

this year) and still appear now, to be quite an improvement over the poor showing of four years ago. A large part of this program's success is attributed to the Commission's setting prices paid for electricity at avoided cost, which is sufficiently high to be attractive to the QF, yet low enough so that the ratepayer remains indifferent. (The present prices the QF, on the average, receives for the QF generated electricity about equals the average rate paid by the ratepayer, within several mills per kilowatt-hour.)"

The staff believes, however, that a rate-of-return penalty should be assessed for failure to negotiate in good faith with hydro developers. This recommendation will not be adopted. The staff's recommendation is based on three or four informal complaints that it has received.

There is no demonstrable evidence of systematic bad faith negotiations in this record.

However, we are concerned about the allegations brought by staff concerning PG&E's negotiating practices with QFs who request nonstandard contracts, and are especially troubled by the testimony of a small hydro developer, N. Ross Burgess. PG&E appears to have set aside for months this developer's request to negotiate a nonstandard contract, without responding in writing to his request. We remind PG&E that in D.82-01-103 we set forth a series of guidelines that would evidence to us the utility's good faith in negotiations with QFs:

> "The utilities are expected and shall be required to bargain conscientiously toward a conclusion. The best evidence of good faith is a collection of written documentation compiled along the way. When the utility is unwilling or unable to accept a QF's proposal, the utility must respond with a timely counteroffer, or an explanation (as proposed by the staff) of:

1. The specific information needed to evaluate the proposal;
2. The precise difficulty encountered in evaluating the proposal; and
3. The estimated date when it will respond to the proposal."

With some QFs, PG&E appears to have been less than careful in following these guidelines. While we will not adopt staff's recommended penalty, we will put PG&E on notice once again, that we expect the utility to abide by these guidelines and to negotiate in good faith with all QFs who wish to pursue nonstandard contracts.

The staff also recommends a second rate-of-return penalty in the cogeneration area. Staff recommends that a five basis point penalty be assessed because PG&E refuses to commit transmission capacity specifically to wind developers in the Solano area.

PG&E has contractually committed 218 MW of transmission capacity to two developers (Aeroturbine and Windfarms, Ltd.) until January 1984. These two developers may not be ready to proceed by January 1984. If they cannot utilize the capacity by January 1984 then staff wants PG&E to commit it to other wind developers. Because PG&E has refused to make the staff's requested reallocation commitment the staff proposes the penalty.

The staff's recommended forced reallocation to other wind developers in the Solano area is an incorrect interpretation of our policy. Thus far we have followed the policy of first-come-first-served in allocating scarce transmission resources to QFs without favoring one technology over another. We see no reason to depart from this policy. Moreover, before committing transmission resources to QFs, we would want to ascertain whether Northwest power would be displaced as a result. For these reasons, we will not adopt the staff's recommended reallocation or its recommended penalty.

E. Transmission and Distribution Efficiency

Two programs in this area deserve discussion: the Conservation Voltage Regulation (CVR) and the 12-21-kV conversion.

PG&E requests $6,236,000 for CVR for 1984. The program was conceded by all to be fully cost effective. The staff recommends full funding. The recommendation was uncontested and will be adopted.

We instruct PG&E to provide staff with its plan to conclude its annual CVR construction program well in advance of the winter storm season so that we may be assured that the CVR projects will be timely completed.

PG&E also requests $16.5 million for 1984 for the 12-21 kV conversion program. The program converts primary circuits from 12 to 21 kV, reducing energy loss. The company has ranked all circuits for conversion based on cost effectiveness. The staff financial witness (Monson) recommended that the proposed request be reduced by over half to $8 million because he believed that PG&E had underspent its 1982 budget for the program by half. PG&E shows that it is on schedule to spend the entire amount authorized by D.93887 ($7.2 million). The full request ($16.5 million) will therefore be adopted. We will, however, treat the CVR and 12-21 kV conversion programs similarly to the other conservation programs and provide for carryover with interest of any underexpenditures in the future.

VI. ELECTRIC MARGINAL COSTS AND ALLOCATION

A. Marginal Costs

This section of the decision concerns the adoption of marginal costs. Traditionally, marginal costs have been used to allocate the revenue requirement among customer classes, to guide the design of specific rates, and to measure the cost-effectiveness of conservation and load management programs. In this proceeding, however, in addition to these purposes marginal costs will also be used to develop payments to qualifying power producers (QFs). When viewed as costs the utility avoids as a result of conservation or power purchases, marginal costs are often called "avoided costs."

A utility's marginal cost is generally viewed as consisting of several components, which may vary depending on the voltage level and whether additional electricity is being generated or avoided. The major components include marginal energy costs and the shortage cost, which represents the value of additional capacity or conversely demand reduction to the utility system. To arrive at the utility's total marginal cost, its marginal transmission and distribution costs are also considered. However, such costs are avoided only if demand is reduced, not if additional electricity is generated by a non-utility service. The cost of adding new customers, the marginal customer cost, is usually not considered, but will be discussed briefly.

TURN takes a different approach to evaluating marginal costs. Rather than calculating each individual component, TURN advocates that the value of marginal utility generation be measured by means of the Market Clearing Price (MCP). While TURN's methodology has some conceptual advantages, problems regarding its implementation remain which prevent our adopting it at this time. We would like PG&E and the staff to perform an in-depth analysis of the TURN methodology and to use it in the next general rate case along with whatever methodology they consider to be the most appropriate.

Our discussion of the various components of marginal cost under the more common approach will be followed by an examination of the TURN method.

1. Marginal Energy Cost

PG&E calculates test year marginal energy costs using a production cost simulation model named GRASS (Generation Reliability and System Simulation Model). The resulting marginal energy costs differentiated by time of day and season and divided by the incremental fuel price equal the incremental energy rates (IERs).[8] Incremental energy rates are used to calculate prices paid to qualifying facilities.

In Exhibits 13 and 13-A PG&E provided calculations of marginal energy costs. The staff checked PG&E's results with its own independent production cost model and basically agrees that they are reasonable. The staff and other parties did have certain recommendations affecting the marginal energy cost, some of which we adopt.

The first recommendation of the staff is that generation line losses should be included in the marginal energy cost calculations for QF pricing. PG&E during the hearing concurred with the recommendation; it was unopposed and will be adopted. The second staff recommendation is that A&G expenses and cash working capital be included in marginal energy cost calculations for QF pricing. PG&E argues that there is no evidence that A&G expenses are truly avoidable; the proposal was supported by no other party and will not

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[8] In this proceeding, IERs were referred to as Incremental Heat Rates (IHRs). However, we now use terminology adopted in D.83-09-054 and refer to IHRs as IERs. This modification is made to reduce confusion about the relationship between the systemwide IER, which is not a heat rate at all, and the heat rates of individual utility plants.

be adopted. Cash working capital was shown by Independent Energy Producers (IEP) to be avoidable. This supports the staff recommendation and the allowance will be included in the IER calculation.

In conjunction with its evaluation of PG&E's Energy Reliability Index (ERI) used in calculating shortage costs, staff made several other recommendations regarding specific generation resources in PG&E's resource plan. While changes in baseload resource assumptions have a greater impact on ERI factors than on incremental energy rates, we agree with IEP that resource assumptions should be consistent for the two calculations, and consider staff's recommendations here.

The first of staff's resource recommendations is that the Geysers Units 19 and 21-24 be deleted from the resource plan. Although their steam supply has been contracted for, a certificate of PC&N has not been granted nor are they sufficiently far along to allow their inclusion as a resource assumption. Another recommendation, one which was accepted by PG&E, is a derating of Pittsburg Unit #7 from 720 MW to 630 MW.

The third recommendation is that the availability factors of the Diablo Canyon and Rancho Seco nuclear plants be reduced by 5%. We agree that the availability factors of 70% and 77%, respectively, used by PG&E for these two plants are unduly optimistic.

IEP argues that the availability factors for Diablo Canyon Units 1 and 2 should be reduced an additional 5% beyond the 65% assumed by staff, for the first two years of operation. After that initial start-up period IEP agrees with the staff recommendation. There is insufficient data in the record to support IEP's contention, and we will adopt the staff recommendation of a 5% reduction.

IEP further points out that the historical average capacity factor for Rancho Seco has been 51.29%, and recommends a 30% forced outage rate for this plant, which translates into a capacity factor of approximately 57%. Given the poor historical performance of Rancho Seco, we agree that a 30% forced outage rate is reasonable.

Staff recommends, and PG&E concurs, that the resource plan include the latest proposed start dates for Diablo Canyon Units 1 and 2 and Helms Units 1, 2, and 3. According to Exhibit 153, the Helms units should be on-line by the beginning of the test year, and the two Diablo Canyon units are projected to become operational on March 31, 1984 and November 30, 1984. We agree with this change.

IEP raises several other criticisms of PG&E's marginal energy cost calculations. IEP argues that PG&E's assumed availability factor of 77% for the existing Geysers units is too high, based on their historical average availability of 71% from 1977 to 1981 and only 62% in 1982. IEP notes also that PG&E projects a 73% capacity factor for its geothermal units in the current ECAC proceeding. We adopt IEP's recommendation that the forced outage rates for Geysers Units 1-15 be increased an aggregate of 5%.

IEP further recommends removal of the NCPA Unit 3 geothermal plant from the test year resource base, on the grounds that the plant is not expected to operate until late in the attrition year. This was not refuted, and will be adopted.

IEP also contends that PG&E understated the test year load forecast. The load forecast used by the staff in verifying PG&E's IER results produces basically the same marginal energy cost as provided by PG&E. Differences in the load forecast affect the ERI but do not appear to warrant an adjustment of the marginal energy cost.

On the other hand, IEP's criticism regarding minimum load conditions appears to have a more solid foundation. The argument basically is that PG&E runs some of its gas and oil-fired plants during times of minimum load as spinning reserve required to meet the following day's peak. If qualifying facilities supplied some of the following day's peak, then PG&E would not need as much oil and gas-fired spinning reserve during minimum load conditions and this should be reflected in the marginal energy costs. The criticism appears to have some theoretical foundation although there was not sufficient evidence to warrant an adjustment to the marginal energy cost at this time. PG&E is instructed to study the phenomenon and adjust its marginal energy cost calculations appropriately by the time of the next rate case.

A final issue raised by IER regards the effect on IERs of the forecasted cost of the predominant marginal fuel on the utility system (assumed to be gas priced at the G-55 rate in this case). Since the average marginal energy cost reflects some portion of time when the marginal fuel is not gas, basing the IER calculation on only the forecasted gas cost biases the results. As data filed by PG&E in Exhibit 261A shows, this effect is not insignificant; a 15% reduction in marginal gas costs can increase the annual average IER by 4.5%.

D.82-12-120 in the OIR 2 proceeding ordered that IERs used for payments to QFs be based only on existing operational resources, with revisions reflecting resource additions to be made in ECAC proceedings. Since PG&E plans that its Helms pumped storage and Diablo Canyon nuclear units will become operational within the test year, it proposes that the Commission adopt sets of IERs reflecting these resources in this decision, to apply on a contingency basis. Staff agrees that this approach could simplify ECAC proceedings.

At the ALJ's request, PG&E developed a series of IER factors and marginal energy costs using the methodology, resource assumptions, and G-55 gas rate we have adopted today; they are contained in late-filed Exhibit 261A and Exhibit 261B. Four sets of IER factors differ in assumptions regarding the Helms pumped storage and Diablo Canyon nuclear units: the first assumes none of them are on-line; the second that the Helms units only are operational; the third that Helms and Diablo Unit 1 are operational; and the fourth that all Helms and Diablo units are on-line.

We agree with PG&E and staff's proposal, and will adopt the four sets of IERs, which are shown in Table VI-1. However, any party can challenge in future ECAC proceedings those IERs adopted for QF payments which reflect Helms and Diablo operation, if it believes that circumstances have changed sufficiently to call their reliability into question. If the Diablo Canyon units become operational before the Helms units, PG&E should file appropriate IERs in the subsequent ECAC proceeding.

TABLE VI-1

Adopted Incremental Energy Rates with Various Major Resource Configurations*
Test Year 1984
(Btu/kWh)

Costing Period	Without Helms Without Diablo 1 Without Diablo 2	With Helms Without Diablo 1 Without Diablo 2	With Helms With Diablo 1 Without Diablo 2
Period A			
On-Peak	13,674	14,086	12,168
Partial-Peak	12,665	13,382	11,369
Off-Peak	10,119	10,499	9,429
Seasonal Average	11,538	12,031	10,515
Period B			
On-Peak	15,410	16,320	14,224
Partial-Peak	14,730	15,689	13,552
Off-Peak	11,353	11,625	10,261
Seasonal Average	13,089	13,692	11,954
Annual	12,427	12,982	11,340

Costing Period	With Helms With Diablo 1 With Diablo 2
Period A	
On-Peak	10,692
Partial-Peak	9,923
Off-Peak	8,489
Seasonal Average	9,322
Period B	
On-Peak	13,303
Partial-Peak	12,694
Off-Peak	9,468
Seasonal Average	11,122
Annual	10,356

* Based on weighted average hydro conditions; includes generation-level losses to the point of interconnection with the transmission grid.

The last issue regarding marginal energy costs is whether and under what circumstances societal rather than utility marginal costs should be used. PG&E calculated societal marginal energy costs using, as the marginal cost of gas, the alternate price of fuel oil rather than the G-55 rate which it uses to calculate the utility marginal cost. Staff recommends that this so-called societal marginal cost not be used for rate design or revenue allocation purposes. We agree.

However, we come to this conclusion realizing that the current G-55 gas rate used in developing marginal energy costs may not be the best estimate of the economic value of QF power, conservation, and load management to the utility system. We instruct PG&E and staff to address further in PG&E's next general rate case the question of what marginal fuel price should be used in evaluating these resources.

We note also that using the price of alternate fuel oil in the marginal energy cost calculation would not of itself result in a true societal marginal cost since many unquantifiable externalities would not be captured.

For revenue allocation and rate design purposes, we will use utility marginal energy costs with the Helms and Diablo units operational as currently scheduled. PG&E filed these marginal energy costs in Exhibit 261A. Adjustments are also made to reflect losses at the transmission and distribution levels. Results are shown in Table VI-2.

Table VI-2
Pacific Gas and Electric Company
Marginal Cost of Energy for Test Year 1984
(mills/kWh, 1984 $)

Time Period	Marginal Energy Costs*	Marginal Energy Costs at Voltage Levels: Generation	Transmission	Distribution: Primary	Distribution: Secondary
Summer					
On-Peak	63.34	63.66	65.45	66.77	67.75
Mid-Peak	59.51	59.78	61.27	62.35	63.78
Off-Peak	50.87	51.03	51.93	52.58	53.07
Winter					
On-Peak	81.51	81.88	83.87	85.33	86.42
Mid-Peak	77.86	78.18	79.92	81.22	82.17
Off-Peak	59.30	59.48	60.44	61.16	61.69
Annual	63.29	63.53	60.83	65.78	66.49

*Includes all variable expenses: O&M and working cash.

2. Marginal Cost of Demand or Shortage Costs

PG&E and staff propose shortage costs based on a combustion turbine (CT) proxy. The shortage cost was described in Decision (D.)82-12-120 in the OIR 2 proceedings as follows:

> "Shortage costs on the utility system at any given time can be defined as the expected cost of an outage at that time or, more precisely, the probability of an outage multiplied by the customer costs associated with an outage. As the probability of an outage increases during peak demand periods (when reserve margins are diminished) and decreases during off-peak periods, shortage costs will be higher during daily and seasonal peak periods and lower during off-peak periods. Shortage costs can also vary on an annual basis, as reserve margins change from one year to the next.
>
> "Because customer outage costs are very difficult to measure on a direct basis, we adopted a proxy for shortage costs in D.82-01-103 and D.82-04-071. Specifically, we used the capital costs of a utility combustion turbine peaking plant, a low-capital cost plant built to meet reliability needs alone, as a proxy for annual shortage costs. This annual shortage cost amount has been allocated disproportionately to peak and semi-peak hours within the year to reflect shortage cost variations."

The only differences between staff's and PG&E's calculations of levelized CT costs are due to different economic assumptions regarding inflation rates and cost of capital. We agree with staff that D.82-12-120 established the appropriate cost of capital and inflation rates for the calculation of CT costs. This resolution of the issue is reflected in our marginal cost tables.

The utilities have argued that annual shortage costs will sometimes differ from the combustion turbine capital cost level. We have agreed, in D.82-04-071 and D.82-12-120, that a more precise refinement which varies shortage costs based on system capacity needs would be desirable.

In the OIR 2 proceedings, PG&E proposed to adjust the combustion turbine costs by its energy reliability index (ERI) which was always to be equal to or less than one. In D.82-12-120 we first reviewed the adjustment and enunciated several shortcomings. In this proceeding PG&E has further refined the concept. A major refinement is that it now recognizes that because of the lead time required to construct a CT the ERI can exceed one during times when the utility is short of capacity.

The Commission staff endorsed the ERI as a second-best proposition. The staff feels that the full CT cost during times of excess capacity overvalues additional QF capacity. The staff also feels that with certain input assumptions changed the ERI-adjusted shortage costs are more accurate than unadjusted costs. We agree. We recognize that during periods of excess capacity the cost of a CT should be adjusted to accurately reflect shortage costs. We make this decision while recognizing the validity of certain criticisms of the ERI brought out by IEP, Occidental Geothermal, and TURN. We also have tried to keep the entire issue in perspective by realizing that marginal energy costs are the largest component of QF prices and that the shortage cost is relatively small.

The most serious criticism of the ERI methodology is that the marginal costs calculated in any year should not be affected by future events. The PG&E-proposed ERI does indeed change due to different assumptions in future years. This is due to the way that PG&E treats an imperfect match between the two reliability indices used in performing the ERI calculations.

The Loss of Load Probability (LOLP) measures the probability that there will be an outage on at least one day in a given year due to insufficient generation capacity. The

Expected Unserved Energy (EUE), on the other hand, measures the expected amount of energy which cannot be provided due to capacity shortfalls. For ERI purposes PG&E has modified the EUE to include volunteer emergency actions that take place prior to a loss of load condition. Because it measures the duration and size of outages, the EUE provides a more accurate picture of system reliability. Since the EUE corresponding to the utility-standard LOLP of one-outage-in-ten years changes every time a computer run is made, anomalous results sometimes occur in comparisons of ERI factors calculated from different computer runs.

This problem arises because PG&E has not adopted an EUE reliability criterion comparable to the utility-standard LOLP of one-outage-in-ten-years. If such an EUE criterion were used, then there would be no need to choose a future base year and ERI factors would be consistent regardless of future resource assumptions.

Since this imperfect match between the LOLP and EUE measures does not create a systematic bias in the ERI factors, we do not believe rejection of the ERI concept is warranted at this time. However, we instruct PG&E, preferably in cooperation with other electric utilities and the staff, to develop an EUE reliability criterion comparable to the LOLP criterion if it presents ERI factors for use in subsequent proceedings to calculate annual shortage costs before this Commission.

The load assumptions used to develop the ERI are controversial. At issue is use of a California Energy Commission Load Forecast versus the PG&E Load Forecast. CEC forecast exceeds the PG&E load forecast by 500 - 2,000 MW. The staff originally recommended the use of the CEC load forecast, but in its brief changed positions and recommends use of PG&E load forecasts. We find the argument raised by PG&E in Exhibit 153 compelling:

> "If PGandE believed that the CEC adopted forecast was more reasonable than its own, the Company's resource plan would be designed to reliably meet the forecasted load. Therefore, it is unrealistic and inconsistent to change the load forecast without making corresponding changes to the resource assumptions."

Since the likely configuration of PG&E's resource plan to match the CEC demand forecast was not examined in this proceeding, we will use the PG&E load forecast. However, in general, we prefer use of the CEC forecast. While PG&E may present comparable evidence using its own load forecast, it is instructed to provide ERI factors using CEC load forecasts in future proceedings.

Various parties have recommended that certain resource assumptions be changed in the ERI calculations. Most of these issues have been dealt with in the section on marginal energy costs. However, one remains which applies only to the ERI factors.

IEP disagrees with PG&E and staff's use of improved forced outage rates for oil/gas steam plants starting in 1987. IEP notes that 22 of PG&E's 33 steam plants are now over 25 years old and that the current trend has been toward higher, rather than lower, forced outage rates. While reductions in forced outage rates are an admirable goal, we agree with IEP that PG&E has not shown any convincing reason why the projected improvement is likely to occur.

A final issue is whether limits should be placed on the ERI factor. PG&E initially proposed that the ERI could exceed one for the first five years and should be limited to one after that, based on a five-year lead time for construction of a gas turbine. Staff argues that a limit, which it sets equal to two, should apply only for the first three years since it believes that PG&E could build a gas turbine in three years on an emergency basis if needed, and PG&E now agrees. Occidental Geothermal notes that PG&E'S CFM IV filing with the CEC shows a lead time of 81 months (nearly seven years) for construction of a gas turbine. Due to regulatory and siting constraints, we agree that a three-year lead time is unrealistic. The ERI limit of two should apply for the first five years, with a limit of one after that.

The adopted ERI factors, calculated using the resource changes we have adopted, are contained in late-filed Exhibit 261, and are shown in Table VI-3.

Table VI-3

Adopted ERI Adjustment Factors

Year	ERI Adjustment Factor
1984	2.00
1985	0.71
1986	0.61
1987	0.62
1988	0.90
1989	1.00
1990	1.00
1991	1.00
1992	1.00

As we can see, the ERI reaches the limit of 2 for the year 1984. It then drops to 0.71 in 1985. We use an average ERI of 1.355 in calculating the marginal demand cost for revenue allocation purposes, since the results will be in effect for two years. Table VI-3 is used to obtain Table VI-4, which shows firm capacity prices to be paid to QFs. The one-year capacity prices should also be used for payments to as-available QFs.

Table VI-4

Pacific Gas and Electric Company
Adjusted Capacity Price Schedule*
Test Year 1984

Operating Date	Contract Life in Years									
	1	2	3	4	5	10	15	20	25	30
1984	156	111	95	88	89	103	114	124	131	137
1985	60	58	59	66	73	95	110	121	127	135
1986	56	58	69	78	85	106	121	132	141	148
1987	61	77	88	95	101	120	135	147	156	163
1988	96	104	110	115	119	136	151	163	173	180

*Levelized $/kW/Year; adjusted for reliability levels.

3. Transmission and Distribution Demand Costs (T&D)

If demand for electricity is reduced or increased, then there are corresponding changes in the need for T&D facilities. Thus, consideration of T&D avoided costs is appropriate for the purposes of revenue allocation, rate design, and evaluation of conservation and load management cost-effectiveness. However, T&D costs are not avoided by utility purchases of QF power, and thus should not be included in payments to QF facilities.

The staff exhibit (Exhibit 62, page 4-5 and 4-6) quoted below succinctly outlines the issues concerning these costs:

> "Decision 93887, dated December 30, 1981, which first adopted shortage costs, focused on shortages occurring in the generation system, but the concept is also relevant to the utility's transmission and distribution (T&D) system. Like generation, transmission and distribution lines have capacity limits that are sometimes approached during system operation. As kW demand increases, so does the probability of a shortage occurring. We estimated T&D shortage component, like PG&E by measuring the relationship of new plant investment to increases in peak demand over 15 years. We did not isolate those expenses occurring only in the test year, because they do not represent necessarily a response to peak growth in just one year.
>
> "They reflect the fact that T&D systems are overbuilt initially in anticipation of future increases in demand. The actual T&D expenditures in any one year may be zero because the investment applicable to that year's needs has already been made. The T&D figures presented in this chapter, do not reflect the shortage costs actually occurring in the test year. They are, again, only proxies which track the long-run marginal costs of transmission and distribution.
>
> "If the ERI mechanism is adopted for generation shortage costs, it would be logical to adjust T&D marginal costs also. The company did not offer a

> reliability index for T&D, admitting that their work in this area was not far advanced. Instead, they assumed that all transmission and distribution resources were added to maintain reliability, making long-run marginal costs good approximations of test year shortage costs."

TURN on the other hand argues that the proposed method of calculating T&D shortage cost was not favored in the last SoCal Edison case. TURN further argues that there is no evidence of the existence of T&D shortage costs and finally that the inclusion or exclusion of T&D cost has no significant effect on the revenue allocation.

We agree with the staff. In the SoCal Edison decision (D.82-12-055) we recognized defects of the proposed methodology and did not include transmission and distribution in the marginal cost calculation. We, however, also agree with the staff that a longer run view of the T&D costs is a fair proxy of the T&D shortage cost until a more accurate method is established. As noted earlier, we also agree with the staff regarding the appropriate cost of capital and inflation rates for calculation of these costs. Adopted T&D costs are shown in Table VI-5.

Table VI-5

Pacific Gas and Electric Company
Annual Electric Marginal Transmission and Distribution Costs by Voltage Level
Test Year 1984

Marginal Cost Component	Voltage Levels: Transmission	Distribution: Primary	Distribution: Secondary
Demand $/kW/year			
Generation	111.06	114.39	117.35
Transmission	21.86	22.51	23.10
Primary Dist.		67.25	68.99
Secondary Dist.			28.84

4. Marginal Customer Costs

There is really no disagreement among the parties on how marginal customer cost should be calculated. The issue is whether marginal customer costs should be used for any purpose. California Manufacturers Association (CMA), California Retailers Association (CRA), Federal Agencies and others contend that the marginal cost used for all purposes should include all elements of marginal costs, and that failure to include marginal customer costs seriously distorts the results of applying marginal costs particularly for revenue allocation purposes. Both the staff and PG&E have calculated marginal customer costs for informational purposes only and have not included them in the total marginal costs. The staff recognizes that the marginal customer costs reflect the number of customers served by the utility rather than changes in output. Basically they measure the cost of serving an additional customer, with or without an increase in load.

Since all uses of marginal costs in this proceeding are related to changes in demand or in utility-owned generation and not to changes in the number of customers, inclusion of marginal customer costs is not appropriate. We agree with PG&E, staff, and TURN, and will not include marginal customer costs in the computation of marginal costs. TURN further recommends that in the future no parties calculate marginal customer costs even for informational purposes. While we will not preclude the parties from calculating whatever costs they deem appropriate, we reiterate that the use of marginal customer costs is conceptually inconsistent with current applications of marginal costs.

5. <u>Marginal Costs by Customer Group</u>

Marginal costs are used in rate design to apportion adopted revenue requirements among customer classes, and are developed for each customer class from the energy and demand costs corresponding to the voltage level at which the class receives service. The marginal cost of demand (including T&D costs) is further adjusted by class load and coincidence factors. Annual marginal costs for a customer class are derived by weighting the on, mid, and off-peak marginal costs by the percentage of consumption in each period. Table VI-6 presents the adopted annual marginal costs by customer class.

Table VI-6
Pacific Gas and Electric Company
Marginal Costs by Customer Group
Test Year 1984
(¢/kWh)

Customer Group	Marginal Cost Components: Energy	Marginal Cost Components: Total*
Residential	6.64	9.64
Small Light and Power	6.82	10.13
Medium Light and Power	6.75	9.97
Large Light and Power	6.66	9.39
Agriculture	6.44	9.69
Street Lighting	6.43	6.46
Railway	6.66	9.42
Other Public Authority	6.66	9.39
Interdepartmental	6.69	9.82

*Sum of columns may not equal total due to rounding.

6. TURN's Avoided Cost Methodology

TURN advocates an approach to marginal cost calculation which is conceptually very different than that taken by PG&E or staff. Rather than calculating each component of marginal cost directly, TURN would measure the value of electricity in the marketplace, and would set marginal costs at the Market Clearing Price (MCP). This concept was described two years ago by an example in D.93887 in PG&E's last general rate case:

> "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. ... 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 called the market clearing price."

A major shortcoming of the MCP approach at this time is that the MCP depends on price elasticities of demand of various customer classes. These elasticities are not available, and appear very difficult to calculate. TURN has shown that the degree of accuracy for calculating price elasticities is not important when marginal costs are to be used for revenue allocation purposes only. However, TURN admits that when the marginal costs are also to be used to determine payments to QFs or for resource planning in general then a much higher degree of accuracy is required.

Another technical problem in TURN's MCP theory greatly concerns us: that is, that whenever the utility attains or exceeds a pre-established target reliability criterion (for example, one day's outage in ten years), additional capacity is considered to be valueless. TURN views this approach as consistent with the illustration of shortage costs given in D.93887. However, it seems to us that a reliability criterion is established with a cost of additional capacity in mind. If the cost of additional capacity falls then a higher reliability level becomes more desirable economically. Thus, the shortage cost is meant to balance the economic costs of a shortage and the cost to the utility of obtaining additional capacity. Only with very large reserve margins would additional capacity be valueless to the system.

Because we want the marginal costs adopted in this proceeding to be used for payments to QFs and for cost-effectiveness testing as well as for allocation of the revenue requirement and rate design, we must reject for the time being TURN's recommended MCP. This does not mean that we have totally rejected the MCP concept. In D.93887 we requested that PG&E attempt to calculate shortage cost directly rather than use a proxy. To date the TURN proposal comes closest to fulfilling this request. We direct both PG&E and the staff to do a more complete analysis of the MCP method of calculating marginal costs. In PG&E's next general rate case we expect to see a calculation of marginal cost using the MCP method. This will not preclude PG&E or staff from providing direct calculations of marginal costs if either believes that methodology is more accurate.

7. Black Box Regulation

In this proceeding many of the marginal cost calculations were performed by computer models. The most notable of these were the GRASS and MARCOST models. At pages 4-9 and 4-10 of Exhibit 63 the staff witness (Toulson) raised the issue of staff access to the computer models. The guidance we provide is rather simple. The staff's access is total and complete. We will not entertain claims of "proprietary computer models" regarding models developed with ratepayer funding.

The staff recommended either that it be trained to understand and operate the models or that an independent auditor be hired to verify them. If these models were to be the only models ever used or if they were not to be used extensively we might endorse the concept of an auditor. However, it now appears that these models will be used extensively and that they will be changed and refined over time. We therefore feel that the recommendation regarding staff training is more appropriate.

The issue of staff access is but part of the larger issue of access by any party to the computer models. We believe that any interested party should have access, though a method of providing such access in a reasonable way was not discussed in this proceeding. We instruct PG&E and staff to address this issue in the next OIR 2-related proceeding.

Another point must be raised: since other utilities use other similar computer models, the staff might have to become expert on several different models. This suggests that uniformity among the computer models of the various utility companies is desirable. We would prefer to see the electric utilities, staff, and interested parties agree upon use of the same production cost and marginal cost models statewide, unless there are serious modelling problems which make this infeasible. We instruct PG&E and staff to work to this end.

B. Revenue Allocation

We have traditionally established electric rates through a three-part process:

1. Marginal cost and revenue requirement
2. Revenue allocation
3. Ratesetting

The first step of this process is complete. The marginal cost calculation affecting class revenue allocation is shown on Table VI-4. We are now ready to proceed to revenue allocation.

We have for many years adopted marginal cost ratemaking. The allocation step involves reconciling the revenue requirement and the revenues that would be generated at full marginal cost pricing. Previously there was a major difference between these two revenue amounts because ECAC revenues were excluded.

The first issue argued by the parties is whether various components of marginal cost should be included in a marginal cost calculation to be used for revenue requirement. These issues were discussed and resolved in this chapter previously. The results are shown on Table VI-4 which is the beginning point of the allocation process.

The next threshold issue is whether the allocation process should include ECAC revenues. We indicated in PG&E's last general rate case that we thought it appropriate that in general rate cases the revenue allocation should include total effective rates. In this case PG&E, staff, and TURN, and others all agree that total effective rates should be subject to the allocation process. We will adopt this recommendation because of the fundamental fact that it is the total effective rate that conveys the price signal to customers. Also, it is incongruous to allocate only base rates by marginal costs of which marginal energy costs are the predominant element. The Industrial Users reconcile this theoretical conflict by suggesting that marginal energy costs should be excluded when applying marginal costs to allocate base revenues. However, we have decided to subject total effective revenues to the allocation process and therefore reject this suggestion.

The third and last preliminary issue concerns PG&E's recommendation that the streetlighting class not be subject to marginal cost allocation. We will adopt this recommendation. We agree that in addition to electricity, PG&E provides the streetlighting class with many additional services such as maintenance and upkeep. Also the streetlighting class uses a rather small quantity of energy compared to the total energy served.

With these threshold questions decided we can now approach the heart of the allocation process by deciding which method should be used to reconcile total revenues with marginal cost revenues.

Before describing in greater detail the various methodologies presented in this proceeding, it is important to review the policies established in Decision 82-12-113, on the rehearing of rate design issues for PG&E's last general rate case. In that rate case, as in all recent PG&E general rate cases prior to A.82-12-48, we addressed rate design to only the base portion of total rates. The design of ECAC and other offset rates was performed in other proceedings.

In that decision, we adopted the Equal Percentage of the Difference (EPD) allocation method for base rates, which is described as follows:

> "EPD is a method of reconciling the difference between revenues at full marginal cost and the revenue requirement. First, present class revenues at average rates are compared to revenues at marginal costs, and the difference between the present class average rate and class average marginal cost is determined. The class average rate for each is increased to meet the new revenue requirement in accordance with the magnitude of the difference between marginal cost and present revenues. The principal advantage of this method is that it moderates rate increases for those classes whose average rates are not close to their marginal cost. Also, this method ensures that all classes whose average rates are below marginal cost will incur some rate increase whenever an increase in rates is required." (D.82-12-113, mimeo, p. 6)

We did not adopt the full Equal Percentage of Marginal Cost (EPMC) method proposed by the California Manufacturers' and Retailers Associations in that decision, because it would result in a dramatic shift of revenues to residential ratepayers, given current class relationships. We also rejected the class marginal rate-class marginal cost (CMR-CMC) proposal made by TURN, because it would shift a substantial amount of support for the lifeline rate to other customer classes, and results in a residential average base rate which deviates significantly from the system average rate (SAR). As we stated in Decision 82-12-113:

> "This is a major departure from our practice in the last several general rate decisions where we have set residential rates such that the average residential rate (taken as a weighted average based on usage levels within the three residential tiers) approximates the system average rate. This practice allows the residential class to support

> the lifeline discount which it enjoys. We think that this remains appropriate and do not choose to deviate from this principle." (D.82-12-113, mimeo, p. 10)

At the same time, we recognized that the adopted EPD methodology does not move towards marginal cost-based class revenue allocations under all circumstances and would require modification in PG&E's next general rate case.

> "We direct the staff and PG&E to develop a modification of the EPD method that will apply to the total effective rate and will also work for rate decreases. We also welcome proposals from other interested parties. We expect this methodology to be developed in PG&E's new general rate case (NOI 78)." (D.82-12-113, mimeo, p. 12)

1. PG&E's Position. In this proceeding PG&E proposed the Equal Percentage Marginal Cost (EPMC) method, which sets the revenue target for each class at an equal percentage of class marginal cost. Under this method, rates are initially calculated at full marginal cost. Insofar as the rates derived from the revenue requirement are different from marginal cost, the difference is allocated on an equal percentage basis among classes.

When ECAC revenues are included with base revenues, residential rates are substantially increased using the EPMC allocation method. This effect was first mentioned in PG&E's Exhibit 20A, page 4 in the following excerpt:

> "While the choice of EPD or EPMC has little impact on class base revenue responsibility, a marginal cost based allocation of energy revenues will increase the residential class revenue responsibility. Because lifeline rates were held constant from 1976 to 1979, the average residential ECAC rate is only $.0278 per kilowatt hour while the average ECAC rate for other customer classes is about $.0363 per kilowatt hour. This imbalance produces about a 17 percent increase in residential class revenue responsibility when total effective revenues, including ECAC, are allocated using either the EPD or EPMC method."

In Exhibit 20A, pages 10-11, PG&E proposed a modification to EPMC for Commission consideration, which would mitigate this effect:

> "To the extent that the Commission may find it desirable to retain the existing relationship between residential and nonresidential ECAC revenue responsibility, PGandE recommends that an adjustment to the EPMC method be adopted which maintains the existing differential while allocating all other revenue changes on the basis of an equal percentage of marginal costs. The preferred method, which is presented in this exhibit, would constrain the first tier residential revenue requirement to 80 percent of the system average rate and allocate the remaining increase or decrease on the basis of the EPMC method."

2. TURN's Position. TURN proposes a modified EPMC method which, similar to PG&E's modified EPMC alternative, establishes the first tier residential rate (lifeline or baseline) at some percentage of the total system average rate, and then applies the EPMC method to the remaining revenue requirement.

TURN's modified EPMC method starts with its class marginal rate-class marginal cost (CMR-CMC) proposal in PG&E's last general rate proceeding. While recognizing the attributes of CMR-CMC that we considered undesirable in Decision 82-12-113, TURN argues that:

> "Modified EPMC is designed to retain the conservation and efficiency benefits of CMR-CMC while remedying the perceived defects in that method. First, under modified EPMC, the revenue allocation is largely independent of residential rate design, particularly the degree of tier inversion (Wells Ex. 80, p. 74; Howard Tr. 3621). Second, the method is relatively easy to apply in either a rate increase or decrease situation (Wells Ex. 80, p. 74; Howard Tr. 3621). Finally, if marginal costs are to be applied to total effective rates rather than just base rates, there will be a substantial revenue shift into the residential class unless a modified EPMC is adopted."

3. Staff's Position. Staff proposes a Weighted Average (WA) method, which combines two allocation methods: the EPMC and the System Average Percentage Change (SAPC) method. The latter approach simply changes the revenue for a given class by the percent change in total system revenues. Unlike the EPD, staff's proposed WA method progresses towards marginal cost-based class revenue allocations under all circumstances. Furthermore, under WA, the Commission can adjust the relative weight given to EPMC and SAPC, depending on how quickly it wants to achieve full marginal cost-based rates. It can thereby mitigate the overall impact on residential rates, without compromising the overall policy objectives articulated in Decision 82-12-113; namely, to move towards EPMC and retain support of lifeline/baseline within the residential class.

4. Adopted Revenue Allocation Method. Moving directly to 100% EPMC would result in a significant, disproportionate increase in revenue allocation to the residential class relative to the system average increase, because the average rates in that class are the furthest away from marginal cost rates, and significantly below system average rates. A 100% weight on SAPC would allocate the increase in system revenue requirements equally, without any consideration of a marginal-cost based allocation.

TURN's and PG&E's modified EPMC methods, on the other hand, would result in an increase in revenues allocated to the residential class which would be substantially less than the system average increase. Other users, in particular those within the agriculture and medium to large lighting and power classes, would experience significant, disproportionate increases. The result of this allocation method is a movement away from marginal cost allocation, and explicitly allocates the costs of residential baseline to other user classes.

We believe that staff's proposed Weighted Average approach represents a clear improvement over the EPD allocation method and is consistent with the policies established in Decision 82-12-113. At the same time, we are concerned that the combination of an overall rate case revenue increase and implementation of the changeover from lifeline to baseline will produce significant and disproportionate increases in electric bills for certain residential users. Accordingly, we are reluctant to move significantly in the direction of EPMC at this time. Furthermore, our goal is not necessarily to achieve full EPMC for the residential class. With each rate adjustment we must continue to be sensitive to the effect of these changes on the bills of individual residential customers. In each subsequent rate proceeding, it is our intention to examine closely and carefully the impact of moving towards EPMC on individual residential customers. Upon our examination we will then determine to what extent we find it reasonable to continue towards full EPMC for the residential class.

We will adopt a 95% SAPC - 5% EPMC allocation method in order to mitigate these impacts, as shown in Table VI-7. Further, as discussed in Section VII, Electric Rate Design, we will adopt baseline quantities and tier structures designed to mitigate the bill impacts on specific residential users resulting from a transition to baseline.

C. Intervening Offset Proceedings

The decision to subject total effective revenues to the general rate case allocation procedure requires some consideration of energy offset or other rate changes occurring between general rate cases. There are three logical methods of allocating offset revenue changes to the customer classes: 1) the traditional equal cents per kilowatt-hour (¢/kWh); 2) the method which we adopt for general rate cases; and 3) equal percentage rate changes.

Table VI-7

Pacific Gas & Electric Company

Adopted Allocation

Revenue Allocation using 95% System Average Percentage Increase and 05% Equal Percentage of Marginal Cost

(Test Year 1984)

Class of Service	Adopted Sales	Present Rates (as of Oct. 19, 1983) Revenue Base	Offset	Effective	Av. Rates	Marginal Cost Data Short-Run Marginal Cost Rates	Revenue	Adopted Rates Revenue Base	Change	Effective	Change	Av. Rate
	(Gwh)	($000's)			(c/kwh)		($000's)	($000's)	(%)	($000's)	(%)	(c/kwh)
	(1)	(2)	(3) <a>	(4)	(5)	(6)	(7)	(8) <b>	(9)	(10) <c>		
Residential	19743	770054	433326	1203380	6.11	9.64	1903225	850673	10.47	1286001	6.69	6.51
Small Lgt. Power	4792	213554	142599	356153	7.43	10.13	485430	234659	9.88	377258	5.93	7.87
Med. Lgt. Power..(d)	13855	520228	412272	932500	6.73	9.97	1381244	579384	11.37	991636	6.34	7.16
Lge. Lgt. Power..(e)	15106	492734	449569	942303	6.24	9.39	1418453	553309	12.29	1002878	6.43	6.64
Agriculture	3454	125078	103387	228465	6.61	9.69	334693	139458	11.48	242725	6.29	7.03
Sub-Total Marginal Cost Classes	56950	2121648	1543053	3664701	6.43	—	5523144	2357465	11.11	3900518	6.43	6.85
St. Lighting....(f)	360	38688	10657	49345	13.71	—	—	31865	-17.64	42522	-13.83	11.81
Sub-Total Sales	57310	2160336	1553710	3714046	6.48	—	—	2389330	10.60	3943040	6.17	6.88
Other Oper. Rev.		17142		17142				16897		16897		
Total Revenue	57310	2177478	1553710	3731188	6.51	—	—	2406227 (g)	10.51	3959937	6.13	6.91

Notes :

<a> Total Offset Revenue for Column (3) (as of Oct.19,1983 Rates) with the following reductions effective from Decision (D.8312049), ECAC $8,456,000 , AER $339,000 ; and $55,000 AER reduction resulting from this Decision.

:ECAC	=	1330347
:AER	=	178422
:CFA	=	7968
:RCS	=	3434
:SFA	=	3984
:A-100	=	3977
:SSA..	=	3384
:Total	=	1553717

<b> Column (8) = Column (10) - Column (3).

<c> Effective Revenues for MC Classes (Column 10) are allocated by 95% of System Average Percentage Increase and 05% Equal Percentage of Marginal Cost. Column 10 = ((0.95 x column 4) x (3900518/3664701)) + ((0.05 x column 7) x (3900518/5523144))

<d> Other Public Auth.:MAPA (A-12 ,A-21) schedules , and Interdepartmental are included in Medium Light and Power.

<e> Other Public Auth.:MAPA (A-22 , A-23) , SLAC , UCB schedules , and Railway are included in Large Light and Power.

<f> St. Lighting Prop. Rev.(42522) by ALJ ordered Cost of Service study

<g> This Decision adopts Test Year Base Revenues of $2,449,000 (proposed Test Year results of operations of $2,472,665,000 less $22,996,000 Load Management Conservation refund). Adopted Rates have been developed to collect $2,406,227,000 in Base Revenues to amortize an estimated $43,442,000 (as of Dec. 31,1983) Electric Revenue Adjustment Mechanism (ERAM) balancing account overcollection during the Test Year.

Historically in energy offset proceedings we have used the equal ¢/kWh to allocate revenue changes. In this proceeding the industrial and commercial groups recommend retaining this method. Their recommendation is based on the arguments that, a) the offset changes reflect changes in energy costs; and b) marginal energy costs are very close for all customer classes. Therefore, offset changes can be allocated on an equal ¢/kWh method. In addition this method is favored by tradition and by its ease of applicability and simplicity. Its main drawback is that it does not reflect total marginal cost. Therefore, the relationships established in the general rate case proceeding can become distorted. If the offset revenue changes are small this distortion is not great, but if offset revenues change greatly, then distortion can become significant.

The second proposal is that the EPMC method be used for the intervening offset changes. This method definitely reflects marginal costs in rates. However, it has several drawbacks. First, the issues raised during the general rate case regarding calculation of the marginal cost might be raised again in the offset proceedings. Secondly, rate design issues raised in general rate cases might also be raised again. It is our hope that the offset cases for electric rates will not be the forum for rate design.

The third method, the System Average Percentage Change method, is simple and uncontroversial. It reflects marginal costs by maintaining the class relationships established with marginal costs principles in general rate cases. This method can easily be applied to rate decreases as well as rate increases in any type of offset proceeding. We will adopt this method of allocating revenue changes in proceedings that take place between general rate case proceedings.

D. Ratemaking Simplification

In this proceeding the ALJ requested that the parties include in their briefs their initial response to the concept of streamlining certain of our ratemaking procedures by combining them i.e. ERAM and AER with ECAC. The responses were interesting but no action will be taken on this subject at this time. We note that for PG&E a consumer's total rate has several components which generally represent balancing accounts:

1. Electric Revenue Adjustment Mechanism (ERAM).
2. Energy Cost Adjustment Clause (ECAC)
3. Annual Energy Rate (AER)
4. Conservation Financing Adjustment mechanism (EFA)
5. Solar Financing Adjustment mechanism (SFA).
6. Residential Conservation Service Adjustment (RCS)

In addition, in this case it was suggested that a Load Management and Conservation Balancing Account or a Research and Developing Balancing Account be established. Other utilities in this state have such things as Major Additions Adjustment Clause (MAAC) balancing accounts. We must determine whether such balancing accounts should be allowed to proliferate.

The responses of the parties were most interesting. PG&E basically responded that although it favors simplification it is opposed to consolidating any of the balancing accounts because it has taken many years to get them in place and does not want to lose any of them.

TURN, on the other hand, favors elimination of certain balancing accounts rather than consolidation, as shown by the following two excerpts from its brief. The first excerpt at page 156 addressed TURN's concern with the ERAM and Attrition Mechanisms:

> "California utilities, and indeed utilities nationwide, have survived for many years without these exotic special adjustments. TURN believes that the time has come to begin pruning back on the proliferation of mechanisms that have sprouted in the last few years. Procedures developed to meet a particular perceived crisis need not continue forever. Regulation is too complex already and needs to be simplified. The time to start is now."

A second passage at page 73, discusses consolidation:

> "At transcript page 3632, ALJ Henderson raised the question of whether ECAC and ERAM ought to be combined into a consolidated adjustment mechanism, similar to the current Gas Adjustment Clause (GAC, formerly GCAC and SAM). TURN does not see any pressing need for such consolidation. The continued separation of these adjustments provides useful information regarding the causes of various rate increases -- whether the source is increased fuel costs or decreased sales. Such data would either be lost entirely or quite difficult to

untangle under the consolidated approach. Moreover, the existence of the Annual Energy Rate (AER) on the electric side is a complicating factor not present in gas operations.

We realize that the postitions of the parties on this issue are only preliminary and are not yet well developed. We do want the parties to continue to devote some thought to the issue of proliferating special rate and balancing accounts.

E. Miscellaneous Issues

1. Request of SCRUB

The School Committee to Reduce Utility Bills made an extensive showing in this proceeding showing how burdensome high utility bills would be and outline the steps that schools have already taken to conserve and reduce bills as much as feasible. SCRUB in this proceeding, at oral argument, most succinctly outlined its five requests. The first request is that schools somehow be afforded special treatment in the allocation step. Its request would require that schools be treated as a separate class. This request will not be granted at this time because there was not sufficient evidence to support such a finding.

The other four requests are outlined in the following quotes:

"Our second request is that the Commission order the utility companies to make regular meter readings on a monthly basis.

"Our third request is that the Commission establish specific guidelines for information on commercial customers' bills.

"Our fourth request, and it's really more in the statement of a support of PG&E's position of rate schedule flexibility and options, but we would like to see schools specifically included in pilot programs for testing various rate schedules so that PG&E can determine the actual impact those schedules have on schools for the purpose of future recommendations to schools, to find schedules that might be the most efficient for both schools and the utility company.

"Our fifth and final request is in the area of load management and conservation. In this area, we would like to see established an ongoing task force consisting of the utility company, the PUC staff and schools."

These requests appear very reasonable and we support each of them. We request both our staff and PG&E to work with SCRUB to accomplish its program outlined above.

Residential Hotels

An issue that was initially raised by the City and County of San Francisco is whether certain hotels should be classified as residential rather than commercial customers. As a residential customer the hotels would get a lifeline or baseline allowance. PG&E argues and the staff concurs that there is no viable definition that would allow only residential hotels rather than all hotels to receive the lifeline allowance.

In two prior decisions concerning the Zero Interest Program (ZIP) and the Solar rebate program, we considered whether to expand the definition of a multifamily dwelling to qualify residential hotels for these programs. In D.82-07-101 dated July 21, 1982 we extended the solar rebate program to include multifamily dwellings with three or more dwelling units, all of which have minimum lease periods of not less than one month and which are occupied at least nine months per year.

Similarly, in D.83-06-048 dated June 15, 1983, we expanded the ZIP program to include multifamily dwellings as defined above. Moreover, we specifically included residential multifamily facilities served by commercial accounts.

We perceive no reason why we cannot adopt a similar definition of multifamily dwellings for the purpose of extending the lifeline, or baseline, allowance to residential hotels. In our view residential hotels should be treated no differently than multi-unit apartment dwellings which currently qualify for lifeline allowances. Eventually, we would like to see both types of dwelling units individually metered.

We therefore find it reasonable to extend the lifeline or baseline allowance to a residential unit where at least 50% of its units are leased for a minimum period of one month and which units are occupied for at least nine months of the year.

We will direct PG&E to make an advice letter filing which establishes a plan for applying lifeline or baseline allowances to residential hotels as defined above. In its plan PG&E shall indicate how it intends to identify residential hotels and to what extent it intends to coordinate its plan with local governments and organizations.

3. Water Pumpers

The Association of California Water Agencies (ACWA) presented a proposed allocation method to benefit their interests. It was actively opposed by both staff and PG&E. No other parties supported it and we will not adopt the ACWA proposal.

VII. ELECTRIC RATE DESIGN

In this proceeding one of the more important rate design items was legislation which was passed and signed last year (Sher Bill AB 2443, Stats 1982, Ch. 1542). We will first discuss Sher Bill implementation issues including tier size. We will then examine the remaining residential rate design issues concerning bill prorationing and TOU rates, and then proceed through the remaining rate schedules.

A. Residential Rate Design

1. Baseline Interpretation

The Sher Bill revised Section 739 of the PU Code to replace lifeline quantities with baseline quantities of gas and electricity for residential customers. The baseline quantities are to be set at 50-60% of average residential consumption with certain seasonal adjustments for all-electric customers. These quantities are to be priced 15-25% below the system average rate and will apply to the first block of an increasing block structure.

There was little disagreement among the staff, TURN, and PG&E regarding most baseline quantities. The following excerpt from TURN's brief outlines the process of agreement:

> "Staff and PG&E initially differed in a number of ways with respect to baseline quantities. In the course of the proceeding, though, PG&E accepted certain of staff's recommendations. One key area where agreement was reached concerned the provision of separate summer baseline amounts for all-electric customers. The absence of such a feature was one of Dr. Wells' major objections to the original PG&E baseline proposal (Ex. 80, p. 79). Similarly, the company has accepted staff's recommended climate bands. Given that our primary criticisms have been answered, TURN does not object to PG&E's

> revised quantities. Either the staff recommendation or PG&E's revised version would be acceptable.

We note that the plain wording of the law requires that total baseline sales be no more than 60% of total residential sales on an annual average basis. The quantities recommended by PG&E produce annual baseline sales which approach 68% of total residential sales. PG&E's results are therefore not in compliance with the statute.

We will therefore adopt essentially the staff's proposed quantities developed in Chapter 6 of Exhibit 62.

The only adjustment that we make to the staff's proposed quantities is the All-Electric Winter allowances. The staff method did not give sufficient weighting to the presence of second homes and to homes with other than electric or gas heating capability nor were the results based on normalized conditions. This deficiency resulted in an incorrectly low all electric winter baseline allowance. We have adjusted these amounts.

The essence of the method that we used to calculate winter all-electric baseline amounts was to average the current lifeline allowances with the staff suggested baseline recommendations. The second tier allowances were also modified. We realized that this appears to favor the all-electric customers particularly those customers in the foothill and mountain areas (Zones Y and Z). These customers have very little sales in the third tier (5% or less) whereas non-all-electric customers have significant sales in the third tier (20%). We feel that this advantage is appropriate because of the very high bills in these zones.

One area of some controversy is the number of residential tiers. PG&E proposed a two-tier design alleging that customers can understand a two-tier system more easily than a three-tier system. Also, PG&E feels that eliminating the third tier will prevent any possible controversy regarding the size of the second tier.

The staff argues in Exhibit 62, page 6-4 as follows:

> "Whether the first point is valid is a matter of conjecture. If a customer cannot understand the meaning of a three-tier rate, how can it be assumed that a two-tier rate will be understood? Also, if one accepts the PG&E argument, then it could be argued that a single rate would be preferable since everyone could understand it. Whether it be a single rate, a two-tier rate, or a three-tier rate, the important point is that the customer should be aware of his marginal cost (the rate that he pays for his last kWh of usage). The present bill format is designed to accomplish that goal and it shouldn't matter whether it showed only two-tiers or three-tiers. The second point that PG&E makes concerning the endless controversy over the length of the second tier (second tier allowance) is a valid one. The Branch proposes to overcome this obstacle by adopting the 'Sher Bill' methodology (a percentage of consumption) to the problem of determining the second tier allowance."

The staff method determined the size of the second tier by adopting the percentage of average residential consumption used in implementing the Sher Bill and dividing the remaining consumption equally between Tiers 2 and 3. The staff argues that this method is consistent with the Sher Bill in that percentage consumption is the basis for the size of Tier 2. The size of the second tier will be adjusted along with any future baseline revisions as average consumption patterns change.

TURN's witness Dr. Wells in Exhibit 80 page 80 commented favorably on this concept as follows:

> "Such an arrangement has a very desirable feature: it sets the average amount paid per KWH in every zone equal (for the same end use). That is, if 57% of the usage in each zone falls into the first block, 22% falls into the second block, and 21% falls into the third block, the average rate per KWH will be the same in every zone since the rates for each residential block are the same throughout the PG&E system. This is also true for winter all elecric usage, although because of the higher percentage of sales in the first block (70%), the average rate would be somewhat less than that paid for basic usage or summer all electric consumption."

Although TURN recognizing the benefits of the staff proposal, TURN opposes its adoption at this time because it fears a change in tier structure would exaggerate the major impacts caused by implementation of the Sher Bill. TURN makes its recommendation, however, without considering two crucial aspects of this decision. First, in foreseeing radical bill impacts TURN assumes a much higher revenue requirement increase then we actually grant in today's decision. Second TURN failed to consider our decision regarding the allocation method. Both the decreased revenue requirement and the adopted weighted average cost allocation method will mitigate any harsh impacts caused by implementation of the Sher Bill as proposed by the staff. Also, all parties agreed that the Sher Bill rates should be implemented on the date of the seasonal lifeline changeover which is may 16, 1984 as discussed in our section on prorationing. This delay will provide a transition period as recommended by PG&E, TURN, and the staff. We will adopt the staff-proposed three-tier rate design with the first and second tier quantities shown in the following table:

Table VII-1

BASELINE AND SECOND TIER QUANTITIES

PG&E Electric Service
Residential 3-Tier Rate Design
(kWh/Month)

Climate Zone	Basic Customer Summer	Basic Customer Winter	All Electric Customer Summer	All Electric Customer Winter
		Baseline		
T	220	250	390	850
V	290	340	540	1100
W	540	320	800	1000
XA	520	350	740	1200
XB	440	350	660	1200
X	310	330	400	1000
Y	350	360	480	1200
Z	250	400	400	1400
		Second Tier		
T	150	170	310	540
V	190	210	340	650
W	460	210	650	660
XA	400	250	510	700
XB	300	230	420	700
X	210	210	360	640
Y	250	250	310	790
Z	230	300	320	880

We will adopt a baseline rate equal to 80% of the system average rate. With the questions of tier structure, baseline rate, sales distribution, and allocation settled, the second and third tier rates result automatically. The Rate Appendix shows the residential rates that will be implemented on January 1, and May 1, 1984 assuming no further intervening rate changes. The January 1, 1984 rates reflect our decision to maintain present residential rate structures until May 1, 1984; thus the present increase is applied on an equal percentage to all three existing tiers.

2. Prorationing

Another issue in residential rate design concerned prorationing of bills during seasonal lifeline (baseline) changes. We thought that this issue had been laid to rest in D.82-12-113. In that decision we exhaustively analyzed the various methods of prorationing and resolved that the then current method was the most accurate. In the present proceeding, however, staff has once again raised the issue, essentially stating that part of our prior analysis was incorrect.

Staff suggests that our analysis of the McKinney method versus the PG&E method was correct and that between those two methods our choice of the PG&E method was correct. However, the staff testifies that we erred in our comparison of the PG&E method with the no prorationing method (Macri). It is interesting to note that in the prior proceeding TURN supported the McKinney method. In D.82-12-113 we essentially stated two serious flaws of the no prorationing method (Macri). The first was that similarly situated customers could have different lifeline allowances at the same time of the year. The second was that different customers could receive different annual lifeline allowances with a six-month winter variance in excess of 30 days.

The staff shows that the first criticism is invalid because it considers only one billing period. If the entire year is considered, with the same assumptions of increasing winter usage and decreasing summer usage, the discriminatory effects are balanced out.

The staff shows that our second criticism is also invalid at page 3-3 of Exhibit 62.

14 I do not agree with the second item - different customers would receive different annual lifeline allowances. All customers with six winter and six

summer billing period will receive the exact same lifeline allowances. For six winter billing periods you receive the winter lifeline allowance for your zone, and for the next six summer billing periods you receive the summer lifeline allowances for your zone.

"15. A concern was expressed on page 35 of Decision 82-12-113 for the potential varying days in a six month winter or summer billing period. I have reviewed the 84 six month billing periods of PG&E from November 1981 through October 1983. Ninety Two percent (77 of 84) of the time the six month billing periods had 182 or 183 days. Only Eight percent (7 of 84) of the six month billing periods were 185 days, and then no more than once in any one of the 21 billing cycles. The 185 day period is followed or preceded by an 182 day period. Thus the varying days in a six month winter or summer billing period are not a problem."

In addition, TURN has reexamined its previous position and now supports the Macri no-prorationing method as shown at page 72 of its brief:

"TURN supports the elimination of prorationing as proposed by Mr. Weissman (and Mr. Macri). Our office has continued to receive customer billing complaints regarding prorationing, despite the 'resolution' of the issue in D. 82-12-113. The suggested use of meter reading dates is much easier to explain to the public than the mathematical intricacies of prorationing. While no approach is likely to satisfy everyone, TURN believes that more of the ratepayers would be satisfied more of the time if they knew that the seasonal lifeline (baseline) change would occur on their meter reading date. That date appears on every customer's bill, and its significance could be explained in the same bill insert that will (presumably) describe the implementation of baseline."

Based upon staff's testimony and TURN's recommendation we will adopt the no-prorationing method as proposed by the staff in Exhibit 62.

3. Residential TOU Rates (D-7)

The issues surrounding residential TOU rates are: first, whether to continue the program; second, whether to expand it and if so how fast to expand; and third, how to structure the rates. We decided the first two issues in our section on Load Management. The remaining issue concerning the structure of the TOU rates will be decided in this section.

The issue of rate design was raised primarily by TURN, which characterizes the program, as presently structured, as a program for the well-to-do. TURN places great emphasis on the issue of revenue transfer between residential customers caused by the current rate structure of this program. This can be restated as a cross-subsidization issue.

TURN correctly points out that the current rate structure does provide revenue transfer to the participating customers. PG&E favors continuing this structure in order to attract customers to the TOU program. The revenue transfer or revenue neutrality issue refers to whether TOU customers should generate the same revenue as they would on the basic residential schedule unless they shift some load. PG&E acknowledges that its proposal retains the revenue transfer of which TURN so strongly complains; however, it argues that the program is still cost-effective from the all-ratepayer (utility) perspective and will provide a major incentive to participate in the program.

PG&E proposes to maintain an effective ratio between on-peak and off-peak period rates of two-to-one, and to replace the current customer charge of $3.00 with a meter charge of $3.50 per month. The effective off-peak rate would be slightly less than the baseline rate.

Staff recommends minor modifications to PG&E's proposal. The customer charge would be eliminated, the off-peak rate would be increased to slightly higher than the baseline rate, and the on-peak rate would then be set residually to recover the remainder of the revenue associated with the customer charge. Thus, the amount of revenue transfer is the same as PG&E proposes.

LGC, Inc., on the other hand, proposes a rate structure that is much more revenue-neutral than the rates proposed by PG&E or staff. The LGC rates are summarized in the table below as LGC 10 and LGC 11. This table compares bills at the PG&E proposed rates for basic residential service (D-1) and for TOU service (D-7) versus the LGC proposed rates.

Table VII-2

Bill Comparisons Under 3 Proposed TOU Rates
($/MO)

Summer

Line	Usage (kwh)	D-1(a)	D-7	LGC-10 (a)	LGC-11 (a)
1	240	17.36	23.80	18.75	17.44
2	500	40.83	45.79	41.50	40.87
3	1,300	128.58	113.45	119.62	128.07
4	2,000	205.35	172.66	187.98	204.36
5	3,500	369.87	299.52	334.46	367.86
6	4,500	479.55	384.10	432.12	476.85

(a) First tier 375 kwh/mo.

It is clear that households on the LGC rates would save less money than those on the PG&E D-7 rate. The LGC witness (Acton) at page 16 of Exhibit 90 addresses this issue:

"There are at least three important reasons for this. First, I think it is important to the long run integrity of the optional TOU rate that it be cost-based and on an equitable basis with respect to other rates. If the Commission is to endorse a permanent TOU rate--as I feel is appropriate--then it is important that the TOU rate not have major cross-subsidies built in which will undermine its long term acceptability.

"Second, the D-7 rate does not have baseline allocations in it; by incorporating baseline features into the TOU rates, we remove a possible source of request for subsidy in the future.

"Third, the incentives and rewards for reducing peak period usage or shifting use to off-peak periods are greater under the LGC-10 and LGC-11 proposals than under D-7. Therefore, households who are willing to make changes which save capital and generating costs to the utility have greater rewards under the proposed alternatives to D-7."

The above testimony shows that adoption of the LGC rate structure would substantially improve the cost-effectiveness test from the nonparticipant perspective. With this result, TURN's strong criticisms of this program would be at least partially rectified.

The LGC-10 rate is based on the ratio of off-on peak marginal costs. Conversely LGC-11 rate is constructed by using the absolute dollar difference between off-peak and on-peak marginal cost. In other TOU rates we have attempted to maintain on and off-peak rates based on the ratio of marginal costs. We therefore favor the method used to obtain the LGC-10 rate. However, we note that it is not nearly as revenue neutral as the LGC-11 rate.

Another aspect of the LGC-proposed rate structure that concerns us is the inclusion of a two-tier baseline-nonbaseline structure within each of the on-peak and off-peak time periods. Thus, TOU customers would face four different electricity prices rather than two. This may unnecessarily complicate the rate structure.

TURN and staff counsel recommend that the peak period for the winter season be redefined. Under the D-7 rate the period is defined as 12 noon to 6 p.m. when the actual winter peak period is 4:30 to 8:30 p.m. We agree in theory that the D-7 rate should more accurately reflect the actual winter peak period and also the summer-winter differential in utility system marginal costs. However, we have doubts about whether such a complicated pricing structure is practical for a residential rate.

In our chapter on Load Management, we have authorized funds to expand the TOU program by 5,000 additional customers with instructions that the next two years be devoted to further experimentation with this program. We believe much further study is needed to determine the best rate structure for TOU customers.

For now, we adopt only minor modifications to the present TOU rate structure. ~~A monthly meter charge of $3.00 will be~~ adopted. The off-peak rate will be set at the adopted lifeline rate, with a two-to-one on-peak to off-peak price ratio. However, we agree with TURN and LGC that rate neutrality should be achieved as soon as possible. We instruct PG&E to develop, in consultation with staff, new TOU rate structures with this result and to file them by advice letter so that they can be implemented by May 16, 1984 when the switch is made to baseline rates.

We are not prepared at this time to dictate the structure of the revenue neutral rates. Since we view the next two years as a period of experimentation, several different rate structures should be tested. However, all existing TOU customers should be transferred to a revenue-neutral rate structure at the time of baseline implementation.

PG&E should propose at least one TOU rate structure along the lines of those presented by LGC in this proceeding. PG&E should also consider changing the winter on-peak period and/or implementing a summer-winter pricing differential. Alternatively, a variation in the on-peak and off-peak periods by climate zones may be desirable to target the on-peak pricing incentives to the periods when customers have the largest discretionary electric loads.

4. Master Meter Discounts

Public Utilities (PU) Code Section 739.5 states that a master meter customer (mobile home park owner) be given an allowance to allow recovery of the reasonable average costs for providing a submetered service to individual mobile home residents. The recoverable cost may not exceed the average cost the serving utility (PG&E) would have incurred in providing comparable services beyond the master meter. The two schedules involved are DT for electric service and GT for gas service.

The ultimate issues in this continuing controversy are 1) the size of the discount, and 2) what form it should take.

PG&E testifies and Western Mobilehome Association (WMA) concurs that the comparable cost for providing gas submetered service in 1984 would be $6.44 per month per mobilehome space.

The major issue in calculating the average electric cost is the weighting factor used to account for overhead versus underground service. PG&E shows that the cost for overhead service will be $7.41 per month per space and $9.60 for underground service. PG&E shows that it serves approximately 93% of the mobilehome parks with overhead service (from PG&E to master meter). WMA shows that about 94% of the individual mobilehome spaces (master meter to mobilehome) have underground service. Thus, the issue is how the average cost should be determined.

We adopt the PG&E method. Since PG&E provides the majority of secondary distribution service to the master meter in overhead fashion, it is reasonable to assume that if PG&E extended the service beyond the master meter it would also use overhead service. Therefore, we adopt the figure of $0.57 per space per month for the electric master meter allowance.

The next issue is what form the allowance should take. Presently it is a percentage discount of lifeline sales. PG&E proposes to maintain this form of the discount. Its chief attribute is that it prevents overpaying mobilehome parks due to vacant spaces. Its major drawback is that the percentage discount needs to be recalculated at every rate change and this presents an additional issue subject to contest during each offset proceeding.

The WMA proposes that the flat rate discount be adopted, noting that it is much less controversial and is then easily applied. It also notes that there are special conditions in both the DT and GT schedules that require the mobile home park owner to notify PG&E when the number of customers change. We will adopt the proposed flat rate discount and encourage PG&E to strengthen its reporting requirements and penalty provisions for failure to report changes in number of customers by advice letter filing.

The other "master meter" schedule DMS should be resolved similarly with the discount provided on a flat rate basis using PG&E's computation of the discount.

B. Light and Power Rate Design

Light and power customers comprise approximately 59% of PG&E's sales but only about 10% of its customers. Approximately 90% of the light and power customers are classified as small light and power and have demand levels below 500 kW. The medium light and power class consists of about 9.4% of light and power customers who have demand levels between 500 and 1,000 kW. Less than one percent of the light and power customers class are classified as large light and power customers with demand in excess of 1,000 kW. The large light and power class accounts for about 45% of light and power sales.

In this proceeding PG&E has proposed numerous though mainly minor changes to the light and power schedules. The Commission staff has done an extensive analysis of the proposals and has set forth its recommendations in Chapter 7 of Exhibit 62.

A general theme underlying PG&E's recommended changes is tariff simplification. PG&E proposes that rate schedules be consolidated and simplified whenever possible. Staff also supports this concept.

A second general theme is that with rare exceptions demand charges should not be increased but kept at current average levels. Customer charges should be replaced by minimum bills applicable to base rates only. These proposals are based on the concept that energy prices are the best reflection of the cost of providing electricity. This is a continuation of our current policy. In a related area PG&E proposes meter charges on the voluntary small light and power TOU rates. These charges are set to recover about half of the meter costs. We agree with PG&E that the customers who benefit from voluntary TOU rates should also bear at least some of the additional metering costs necessary to provide them this rate option.

The staff has proposed a restructuring of TOU rates which would account for seasonal variations in marginal costs. Currently, the same average TOU rate is maintained throughout the year, though the relationship among rates in the on-, mid-, and off-peak periods changes seasonally for some schedules. PG&E supports maintaining the status quo. We agree with staff that the present method does not adequately recognize marginal cost differentials. However, as staff recognizes, radical rate changes might result if the actual seasonal differentials were reflected all at once. We will begin to make this transition, however.

We adopt a modification of staff's alternate proposal, and recognize the differential between seasonal average marginal costs to the extent that results in a percentage increase in summer average rates which is twice the increase in winter average rates for a given schedule. To allow greater time differentiation of marginal costs within each seasonal period, we maintain both summer and winter off-peak rates at the current levels and recognize marginal cost differentials in the on- and mid-peak rates, with the further constraint that summer on-peak rates are allowed to increase at most 25%. The desirability of moving further toward complete recognition of marginal costs should be examined in PG&E's next general rate case.

1. Small Light and Power

(a) Schedule No. A-1

This is a flat energy rate schedule which serves most of the small light and power customers. We adopt PG&E's proposal to substitute a minimum bill for the customer charge.

(b) Schedule No. A-7

This is a new proposed experimental TOU schedule for small light and power customers, who are not now offered TOU rates. Since the A-7 rate will not be seasonally differentiated to reduce meter costs, staff recommends setting these rates to reflect the differentials of the seasonally weighted average marginal costs. PG&E would establish on-mid-off peak ratios of 2:1.3:1 for this schedule. Both PG&E and staff would structure the rates so that the weighted average rate is the average rate for the class.

We will authorize a modification of staff's alternate proposed rate design. We establish the off-peak rate at the weighted average off-peak marginal cost, and the on-peak rate at the weighted average on-peak rate charged to Schedule No. A-21A customers including demand charges.

We agree with PG&E that a monthly meter charge of $3.75 per customer is appropriate. In the next general rate case, we expect to see a comparison of Schedule No. A-7 and Schedule No. 21-A, which has both a demand charge and a seasonally differentiated energy charge, and which is also being opened to the small light and power class.

(c) Schedule No. A-15

This schedule is applicable to a limited area of San Francisco, Oakland, and Stockton where service is direct current. We authorize the substitution of a minimum bill in place of a customer charge.

(d) Schedules Nos. A-20A, B, C, and D

These are experimental TOU rates which are scheduled to end on January 1, 1984. PG&E proposes to close these schedules and to transfer the customers presently on them to Schedules Nos. A-1, A-7, or A-21A at the customer's choice. We adopt the proposal.

(e) Schedules Nos. A-T and A-D

PG&E proposes, on an experimental basis, an interruptible Schedule No. A-T, and a load cycling Schedule No. A-D for small light and power customers with central refrigeration air conditioning. Customers would be billed according to the normally applicable schedule and given a specific discount per kW or per ton of guaranteed interruptible load during the summer months only. Staff recommends that discounts on these two schedules be based on marginal generation costs saved by these customers, with adjustments based on benefit/cost analysis. Since these are experimental rate schedules, we will authorize these rates with the discounts as computed by PG&E. We will consider staff's recommendations when we evaluate the effectiveness of these rate schedules.

2. Medium Light and Power

(a) Schedule No. A-12

PG&E proposes to eliminate this schedule which has a flat energy rate and a declining-block demand charge. Customers currently on Schedule No. A-12 would be placed on Schedules Nos. A-1, A-21, or A-7 depending on their choice and usage patterns. The staff first supported the immediate elimination of this schedule but during the hearing modified its recommendation. The staff now recommends that A-12 be phased out over a two-year period because not all A-12 customers who so desire could be accommodated on a TOU schedule (A-7 or A-21) immediately. The staff also recommends reducing the A-12 demand charge to a flat $1.70/kW, which is the current average level for Schedules Nos. A-22 and A-23. Staff further recommends converting the $20 per month customer charge to a minimum charge.

We will adopt the staff recommendations concerning this schedule.

(b) Schedule No. A-21

This is a demand-metered TOU tariff which is mandatory for customers with peak loads between 500 kW and 1,000 kW. It is experimental for customers with peak demand less than 500 kW (Schedule No. A-21A). PG&E proposes and staff concurs that the customer charge be replaced with a minimum monthly bill of $20.00. We adopt this proposal. PG&E suggests a demand charge of $2.80/kW; the staff recommends $1.70/kW. The staff proposal, which we adopt, is part of a consistent proposal that the $1.70/kW demand charge be equal for Schedules Nos. A-12, A-21, A-22, and A-23 because the distribution-related costs are not significantly different for customers on these schedules. Also, PG&E proposes a meter charge of $10 per meter per month for Schedule No. A-21A. Staff opposes this charge. We will adopt this meter charge for the same reasons that we accept meter charges for all voluntary TOU rates. The TOU rate differentials will be established as discussed previously.

3. Large Light and Power

(a) Schedules Nos. A-18 and AS-18

These rates provide an interruptible/curtailable service option for customers with at least 500 kW of interruptible load served at voltages of 2 kV or higher. Energy rates on Schedule No. A-18B are discounted to provide incentives for customers to allow their service to be interrupted and are referenced to marginal energy costs only, since these interruptible customers should not place capacity demands on the utility system. The staff proposes that the A-18 schedule be incorporated into A-22/23. Under the staff's preferred approach, a special option would be created to correspond to the curtailment criteria currently in effect in Schedule No. A-18, and the resulting discounts would be consistent with the criteria in Special Condition 10 in Schedule No. A-23. Thus, the electricity rates would be referenced to both marginal energy and marginal capacity costs, and the discounts paid to customers would depend on the number of curtailments actually experienced.

Staff proposes that, if Schedule No. A-18 is retained, then the rates for winter and summer seasons should be differentiated to reflect the seasonal marginal energy cost differentials and that the A-18 average rate should be gradually moved toward the energy-only marginal costs.

PG&E proposes that A-18 be retained while eliminating A-18A.[9] We agree that A-18A should be eliminated. We believe that perhaps in the future A-18 should be combined into A-22/23 but to do so at this time would unnecessarily complicate the A-22/23 schedule. However, we will require PG&E in its next general rate case to present a rate structure which incorporates the recommendations proposed by staff.

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9 Schedule A-18A applies to customers with demands greater than 5,000 kW and consists of a flat energy rate and time-of-use demand rate. This schedule has attracted few customers.

We note that, with the marginal costs adopted today, average A-18B rates bear approximately the same relationship to marginal energy costs as A-23 rates do to total marginal costs. Thus, both schedules should receive the class average rate increase. We note further that the marginal energy component of total marginal costs is higher in the winter than in the summer. Since our goal is to incorporate A-18 into the A-22 schedule within two years, we do not believe it appropriate to reflect this seasonal differential in the A-18 rates. We will, however, increase the spread between on- and mid-peak rates slightly.

Schedule No. AS-18 is an interruptible rate applicable to steel producers as a result of SB 1547. Staff recommends that the full energy rate discount, set at 55% of the system average rate, apply only for automatic interruption (without notice). Lesser discounts would apply for interruptions made after 10-minute and 30-minute notice periods. These discounts would be based on avoided marginal generation costs per kW. PG&E's proposed Schedule No. AS-18 has no provision for automatic interruption.

Because there is little development of the basis for the varying discount levels, we will not adopt staff's proposal at this time. We do, however, find conceptual appeal in staff's proposal and will direct PG&E to develop in its next general rate case a schedule which reflects the different values of interruptible options to the utility.

(b) Schedules Nos. A-22 and A-23

PG&E proposes to consolidate Schedule No. A-23 into Schedule No. A-22. The schedules were made identical in January 1982 except for the curtailment provisions of A-23. PG&E proposes to extend the curtailment provisions of A-23 to A-22, thus eliminating the final difference between the two schedules. The staff supports this proposal. For reasons discussed previously, we will adopt the staff's demand charge, the utility's minimum bill, and the seasonal differentials between rates discussed previously. We also adopt PG&E's proposed designation of curtailable load.

PG&E proposes to maintain the current discounts in Special Condition 10. These discounts were established at a level to capture the marginal cost of generation per kW per year when the maximum number of curtailments occurred. Because PG&E's marginal costs show a decrease from the cost levels previously used to establish the discounts, PG&E proposes no change in the discounts.

Staff recommends recalculating the discounts based on the most recent marginal cost values regardless of whether they are higher or lower than values used to set the discounts.

While we generally agree with staff, we are not prepared to recalculate the discounts offered under this schedule without further analysis of whether the incentive for participation varies significantly with periodic discount adjustments.

Staff also recommends increasing the curtailable options under Special Condition 10 to allow for 15-minute, 30-minute, 1-hour, and 4-hour warning periods prior to curtailment. The discounts would be based on avoided marginal generation cost per kW under each of these options. Again, we will require PG&E to develop these options for our consideration by the time of its next rate case.

The last issue for this schedule regards certain penalties. The schedule provides that customers who fail to curtail load when requested by the utility should be penalized. The staff has demonstrated that the present penalties are inadequate, but offers no alternatives. We agree that the penalties are inadequate and direct PG&E to prepare more appropriate penalties and submit them for approval via an advice letter filing no later than April 1, 1984.

(c) Voltage Discount, Power Factor Adjustment and Standby Rates

PG&E proposes and the staff agrees that 1) the reference power factor adjustment be increased, 2) the voltage discount be increased, and 3) standby charges be increased by 7%.

The reference power factor charges were vigorously opposed by CMA. We do not believe that the record in this proceeding is sufficiently well developed on this issue to adopt the proposed change of the reference power factor. The other proposals involving the voltage discount and standby rates will be adopted.

C. BART and Public Authority

PG&E proposes that the demand charge be increased to be consistent with A-22. We will not adopt this change, noting that we did not increase the A-22 demand charge to the level requested by PG&E.

However, we will adopt the proposal by PG&E that the Public Authority rates be increased based on the increases applied to the corresponding light and power classes.

D. Agricultural Service

The agricultural class is served primarily under two rate schedules, PA-1 and PA-2. About 89% of agricultural customers, comprising 55% of sales in this class, are billed on Schedule No. PA-1. This schedule has a flat energy rate, a demand rate, and a customer charge. Schedule No. PA-2 is a TOU schedule for customers with loads greater than 35 kW. Schedule No. PA-R is a variation of Schedule No. PA-2 which alternates a higher on-peak rate every other day and has no demand charge.

We will adopt PG&E's proposals for demand charges and minimum bills for Schedules Nos. PA-1 and PA-2. However, we agree with our staff that eventually the PA-2 demand charge should be made consistent with the PA-1 demand charge.

As for other TOU schedules, we agree with PG&E's imposition of a ~~metering charge for Schedule No.~~ PA-2.

PG&E proposes to set the rates for agricultural schedules by maintaining the current difference between the average rates for the PA-1 and PA-2 schedules, and the current differentials among on-, mid-, and off-peak rates for the PA-2 schedule.

Staff proposes to establish the same average energy rate for the PA-1 and PA-2 schedules, thus eliminating the current discount built into the PA-2 rate. Further, staff would establish TOU differentials that correspond to marginal cost differentials, recognizing seasonal differences ~~as discussed previously.~~ The percentages of usage on-, mid-, and off-peak used to calculate the rates in staff's proposal are the averages estimated for the entire class.

We agree with staff's approach. However, as in the Light and Power TOU schedules, these changes must be implemented gradually to prevent radical rate changes. We adopt a modification of staff's proposal for PA-2. The average PA-2 rate is set equal to the energy rate adopted for PA-1, and ~~the differential~~ between seasonal average marginal costs is recognized to a certain extent. The increase in the summer on-peak rates is limited to 25%. To meet these restrictions, the off-peak rate must be increased slightly. We also increase the spread between on- and mid-peak rates slightly. The desirability of moving further toward complete recognition of marginal costs should be examined in PG&E's next general rate case.

PG&E proposes a new TOU rate (PA-3) for customers with loads between 10 and 35 kW and an interruptible option Schedule PA-T for customers with demands less than 10 kW. For Schedule PA-3 PG&E also proposes to set the off-peak rate equal to the PA-2 off-peak rate, and to determine the on-peak rate residually. Staff observes that since the off-peak period defined for PA-3 includes hours that are actually mid-peak, setting the off-peak rate equal to the PA-2 equivalent rate does not realistically reflect cost. Staff, therefore, recommends that the on-peak rate should be set equal to the weighted average PA-2 on-peak rate and that the off-peak rate be determined residually. We believe that staff's proposal will provide sufficient incentive for the customer to shift its load to off-peak. For this reason, we favor and will adopt staff's proposal. We adopt, however, PG&E's proposed meter charges.

We will also adopt PG&E's proposed PA-T schedule as an experiment.

Schedule No. PA-R is a load management schedule designed for customers who can vary their peak usage patterns every other day. PG&E proposes a meter charge which we will adopt. PG&E proposes to set on-off peak rates equal to corresponding PA-2 rates, and the alternate day incentive rate equal to the rate differential between seasonal periods.

Staff suggests setting the restricted on-peak rate at a set percentage above the nonrestricted on-peak rate and maintaining the off-peak rates at the marginal cost differentials.

Due to the existing PA-R rate structure, our intent to establish PA-2, PA-3, and PA-R rates with equivalent average energy rates, and the low revenue increase granted today, both PG&E's and staff's approaches would create substantial swings in certain components of the PA-R rates. We therefore increase each component by the 0.9% needed to produce an average PA-R rate equal to the new average PA-2 rate. If PG&E determines that changes to the resulting PA-R rate structure are needed to enhance its experimental effectiveness, it may propose revisions through an advice letter filing.

E. Streetlighting

The streetlighting rates in this proceeding receive quite different treatment from other rates. PG&E showed in an updated cost study (Exhibit 20-E) that our historical treatment of streetlighting rates had resulted in very high rates. The updated cost study (marginal and average) showed that streetlighting rates should be reduced substantially. The California City/County Street Light Association (CAL-SLA) supports PG&E's revised Exhibit 20-E but believes that the study contains various ratemaking errors. We agree that the study might contain errors, but we will accept it as a much more reasonable approach than the initial PG&E proposal in Exhibit 20. While we accept the PG&E proposal we also will adopt certain suggestions of CAL/SLA regarding future general rate case proceedings. The first suggestion is that PG&E and the staff perform an updated cost study for streetlighting for consideration in the next general rate case. We also adopt the suggestion that PG&E attempt to propose an unbundled rate design for streetlighting.

A sub-issue related to the streetlighting service rates is the contract rates applicable to the City and County of San Francisco (San Francisco). San Francisco's rates are subject to an increase or decrease in accordance with the rates applied to other customers for similar service. For San Francisco a similar service is provision of ownership and maintenance. San Francisco showed in cross-examination that a 24% decrease in its rates based on Exhibit 20-E would be a reasonable minimum. We adopt this percentage decrease.

VIII. GAS MARGINAL COSTS AND GAS RATE DESIGN

This decision will not, in itself, result in a set of gas rates. Rather we will discuss gas marginal costs and present revised gas rate design guidelines. These results are carried over to PG&E's GAC (A.83-08-038) proceeding decision, also issued today, to produce the actual gas rates.

A. Gas Marginal Costs

Gas marginal costs are infinitely less complicated than electric marginal cost. PG&E presented a marginal cost methodology which fits well with its marginal cost theory for electricity.

We also note that TURN is in substantial agreement with PG&E's theory. TURN is also able to show a great similarity between its Market Clearing Price theory and PG&E's marginal gas cost theory.

The basic equation for gas marginal costs presented by PG&E is:

Marginal Cost = Marginal Operating Cost + Shortage Cost.

PG&E shows that marginal operating cost is the incremental costs PG&E actually incurs, thus:

Marginal Operating Cost = Marginal Acquisition Cost + Marginal Transmission Cost.

Next, PG&E shows that the calculation of gas shortage costs is much simpler than that of electrical shortage costs because of the existence of an almost perfect substitute--alternate fuel oil. Therefore, shortage cost equals the difference between marginal operating cost and the alternate price of fuel oil. Thus marginal cost equals the price of alternate fuel oil, as long as the latter exceeds or equals the marginal operating cost.

TURN's theory assumes that the short-run marginal cost is equal to the greater of the marginal operating costs or the market clearing price and that the market clearing price is equal to the price of alternate fuel oil.

Staff acknowledges the shortage concept. However, staff assumes a very rapid convergence of marginal operating costs and the alternate price of fuel oil. This would result in shortage costs equalling zero.

We will adopt the view of marginal costs presented by PG&E and TURN. The price of gas should not go below the marginal operating costs. Also, because the price of alternate fuel exceeds marginal operating costs, fuel switching should not be encouraged.

We therefore have developed a range of appropriate prices for gas. One boundary is the marginal acquisition and transmission costs, plus a premium representing the long-term value of gas. The other boundary is the price of alternate fuel oil, plus any premium that might be attached to gas usage. This range then becomes the foundation of our gas rates in accordance with our policy that gas customers should pay as close to the utility's marginal cost as revenue constraints and minimization of uneconomic fuel switching allow.

With the major theoretical issues resolved, the more pragmatic issue of determining the price of alternate fuel oil is presented. The choice is:

1. PG&E's long-term contract price for fuel oil or,
2. The spot market price.

TURN supports the first choice. TURN posits a situation in which demand exceeds supply thereby requiring curtailments. TURN then argues that Priority 5 customers (power plants) would be curtailed first, and that therefore the alternate price of fuel oil faced by these customers represents the price of alternate fuel for marginal cost purposes.

We disagree because we are not now in a period of P-5 curtailment, nor is one forecast in the test period. The spot market price is the price of alternate fuel faced by all customers with fuel switching capability irrespective of the curtailment situation. We therefore believe that the spot market price of fuel oil should be used as the marginal cost.

B. Gas Rate Design

The first question that we must answer is what is the purpose of gas rate design guidelines. We feel that the presence of guidelines serves the major purpose of focusing the parties on particular issues. We realize that guidelines that were intended to remain in place for two years have been changed in intervening rate cases. We hope that these guidelines will not need to be changed excessively before the next general rate case. The guidelines should give the parties who appear in our cases a pretty firm idea how their rates are likely to change in future offset cases depending on various circumstances. With these purposes in mind, we will continue to establish guidelines even though they may change with circumstances. To minimize these changes we will take TURN's suggestion and try to set guidelines that can encompass as wide a range of circumstances as possible.

1. Preliminary Residential Gas Rate Issues

(a) Prorationing Bills

We adopt the staff position on pro-rationing bills during seasonal lifeline (baseline) changes. This issue was discussed extensively in our electric rate design chapter and the discussion will not be repeated here.

(b) Sher Bill Baseline Implementation

(1) Quantities

Both the staff and PG&E calculated applicable baseline quantities. The suggested quantities are virtually identical. TURN supports either set of figures. No other parties contested either set. We will therefore adopt the baseline quantities proposed by the staff in Exhibit 62 shown in the following table:

Table VIII-1

Pacific Gas and Electric Company
Gas Department
Proposed Baseline Quantities

55% of Average Aggregate Consumption SUMMER

Climate Zone	Single Family Use Therms	Multi-Family Use Therms	Combined* Multi & Single Family Use Therms	Proposed Baseline Therms (PG&E)	Present Lifeline Therms	Minimum Baseline Therms (50%)	Maximum Baseline Therms (60%)
T**	[illegible]	22	27	30	50	24	30
V**	26	19	25	25	61	22	28
W	19	14	18	20	25	16	20
X-A	22	15	20	20	26	19	23
X-B	22	15	20	20	26	19	23
X	22	15	20	20	25	19	23
Y**	25	19	25	30	50	23	30
Z	currently no gas customers			30			

70% of Average Aggregate Consumption WINTER

Climate Zone	Single Family Use Therms	Multi-Family Use Therms	Combined* Multi & Single Family Use Therms	Proposed Baseline Therms (PG&E)	Present Lifeline Therms	Minimum Baseline Therms (50%)	Maximum Baseline Therms (70%)
T	80	58	59	70	82	[illegible]	69
V	71	48	67	70	106	54	67
W	74	49	70	70	87	57	70
X-A	87	[illegible]	75	75	106	60	75
X-B	88	47	75	75	106	60	75
X	87	47	75	75	106	60	75
Y	86	42	62	65	77	50	62
Z	currently no gas customers			65			

* The combined column is the adopted baseline allowance for the respective climate zones.

** Zones T, V, and Y currently have a summer heating allowance.

(2) Implementation Date

As indicated in the electric rate design chapter, there is virtual consensus that the baseline quantities should be implemented on May 16, 1984.

(c) Residential Tier Structure

Both the staff and PG&E proposed changing from a three-tier to a two-tier rate structure. Again, TURN supported the proposal and no one opposed it. We will adopt the two-tier rate structure, for the primary reason that marginal gas cost is below system average rate.

In PG&E's next GAC offset proceeding, it is directed to show the sales by tiers that result from the implementation of baseline quantities. The changes in the sales at the tier levels will result in a second tier rate decrease which will be implemented in our decision in that proceeding.

(d) Master Meter Discount (G.S. and G.T.)

The master meter discount problem was discussed extensively in the chapter on electric rate design. The same reasoning is applicable to master meter gas customers and we will adopt the same result. The discount will be a flat rate discount using PG&E computation of the amount of the discount.

(e) Central Water Heating (G.F.)

The company proposed elimination of the G.F. schedule. The staff favors its retention. We will adopt the staff's recommendation because PG&E did not offer sufficient analysis to substantiate a need to eliminate the schedule.

2. Rate Design Guidelines

This decision will contain many but not all applicable rate design guidelines. These will be repeated along with all other guidelines in PG&E's GAC offset decision also issued today. The guidelines specifically decided in the GAC pertain to the indexing and structure of the G-50 rate and to modifying the G-58 rate.

Also as a preliminary matter, the rates ultimately produced by our guidelines will produce total effective rates rather than preliminary rates to which we would add the RCS, CFA, SFA, and GEDA revenues as we have in the past.

(a) Resale Rates

PG&E's gas system includes four resale customers:

1. City of Palo Alto
2. City of Coalinga
3. C. P. National
4. South West Gas Corporation.

Of these four customers we directly regulate the rates of the latter two customers. We indirectly regulate the rates of the City of Palo Alto because it is a territory entirely surrounded by PG&E's territory and charges its customers the same rates as PG&E.

The Palo Alto rate has been the subject of unceasing controversy. Presently, the Palo Alto rate is established at 85% of PG&E's system average rate. This method has provided satisfactory results for Palo Alto but bears no resemblance to the method used to develop the other resale rates. The other rates are based on the sum of average cost of gas, franchise fee and uncollectible adjustments, the other offset adjustments (CFA, SFA, RCS, and GEDA), and a base cost contribution. To make Palo Alto's ratemaking treatment consistent with other resale rates statewide, and at the same time not harm Palo Alto's margin we will adopt the concept of the "ratesetting utility".

Our interpretation of the ratesetting utility concept is that Palo Alto and Coalinga should pay the same rate as CP National and South West Gas Corporation including all the add-ons, and that none of the resale rates should exceed 85% of PG&E's system average rate. This will place the ultimate ratepayers on equal footing as far as the utilities' access to gas at an equal cost.

With our resale and preliminary residential rate design discussion completed, we can now address the remaining rates which are based on marginal cost concepts. Once again we repeat that our fundamental rate design principle is that all rate payers should pay as close to the utility's marginal cost as possible while minimizing uneconomic fuel switching. The other major consideration is that radical rate changes should be avoided. The following table outlines various critical elements of gas rate design and shows how they are now related for the three major California gas utilities.

TABLE VIII-2

(¢/therm)

	PG&E	SoCal Gas	SDG&E
1. Marginal Operation Cost (Swing fuel)	35.62	35.62	44.958
2. Average Cost of Gas	39.9	39.9	44.163
3. Marginal Cost (Alt. Fuel Price)	48	48	48
4. System Average Rate	54.223	56.43	60.0
5. Average Electric Generation Rate	53.9	51.67	50
6. Average Residential Rate	51.4	60.4	66.8

The two most important elements are the system average rate and the marginal cost (alternate price of fuel oil). For all three utilities, the system average rate is higher than the marginal cost. As a result, we must determine how this deficit is to be shared or made up among the customers.

Our primary concern is to avoid uneconomic fuel switching. This needs to be further explained. Uneconomic fuel switching in theory would occur, for example, if customers switch to fuel oil when its price is above marginal gas operating costs. This means that we should encourage customers to stay on the gas system by assessing potential switchers a favorable rate down to 35.62¢/therm. However, we have previously decided that gas should not be sold at such a low rate and that a 12% premium would reflect the long-term value of gas use. Therefore, the lowest rate allowed should be 35.62¢ + 12% = 39.9¢/therm. We also feel that many customers are willing to pay a premium above the alternate fuel price without switching fuels. First of all, customers that have only No. 2 alternate fuel oil capability can pay the No. 2 alternate fuel price without switching. Also we believe that many potential fuel switchers should be willing to pay a premium in the range of 5-10% above their alternate fuel price to burn gas.

As stated previously, the alternate fuel price to PG&E's electric department is 48¢/therm (spot market price). Other industrial customers probably face No. 6 fuel prices in the range of 46¢ to 56¢/therm, while No. 2 fuel oil prices probably range between 5¢ to 10¢/therm higher than No. 6 LSFO.

With this discussion of alternate fuel prices, we can proceed to our main problem in gas rate design. As suggested earlier, the ultimate issue in our present pricing environment is how to recover the difference between marginal cost based revenue and the revenue requirement. The most obvious way of recovering this deficiency when average costs exceed marginal cost is with demand or capacity charges. However, this record contains insufficient evidence to determine the application of capacity charges. The other possibility, which we will adopt, is to increase commodity rates while not encouraging fuel switching.

Our previous discussion of alternate fuel prices puts a cap on the prices that can be charged to industrial users. The guidelines for these industrial customer schedules (G-50 and G-58) are discussed in PG&E's accompanying GAC decision. The remaining industrial rates are the G-57 (So-Cal Edison) and the G-55 (PG&E Electric Interdepartmental) rates.

G-57

In the past we have treated G-57 and G-55 equally because they represent the same end-use. In the accompanying GAC decision, we conclude that G-57 should continue to be treated in this manner.

G-55

PG&E is a combined gas and electric utility. The fuel switching issue is not faced by the gas department in pricing gas to the electric department. Thus establishing the G-55 rate will involve substantial judgment as well as careful consideration of the following factors:

1. PG&E marginal cost (48¢/therm)
2. PG&E's contract fuel oil price (53.9¢/therm)
3. System average cost of gas (54.223¢/therm)

While we realize that any price above the marginal cost does not contribute to economic efficiency, we also are faced with a revenue requirement deficit. In the absence of a substantial capacity charge we believe that a G-55 rate that is set at PG&E's contract fuel oil price is equitable to the ultimate electric customers, particularly when the resulting electric rates are below electric marginal cost.

G-52

Earlier in this proceeding we adopted a G-58 schedule that was designed to prevent true fuel switchers with No. 6 fuel oil burning capability from leaving PG&E's gas system. The G-50 rate is for potential fuel switchers with No. 2 fuel oil burning capability.

There is, therefore, no reason to maintain the G-52 schedule. We will authorize its cancellation as requested by PG&E. All customers currently on G-52 are eligible for either G-58 or G-50.

G-2

The next schedule to be discussed is applicable to industrial and commercial customers with no alternate fuel capability. The theoretical cap on the G-2 schedule is probably the price of propane plus a small premium. Thus, there is currently some leeway in establishing G-2 rates before fuel switching for this class becomes likely. However, we recognize potential limits on the ability of these customers to receive future increases.

G-1 Residential

Under present legislation the first tier residential rate is established at 85% of the system average rate. Thus, our focus will be on the second tier and the residential average rate. A review of Table VIII-2 discloses that one of the relationships that is not consistent among the three utilities is the relation of "Residential Average Rate" and the "System Average Rate." Only on PG&E's system is the residential average rate below the system average rate. The residential average rate is about halfway between the marginal cost and the system average rate. We believe that this rate should move somewhat closer to the system average rate and perhaps even approach the system average rate if necessary to prevent fuel switching. With the first tier rate set legislatively, the second tier must be set residually.

With the general discussion above we can now set forth the specific guidelines.

Step 1. Adopt a sales profile, marginal cost (alternate fuel oil price), marginal operating cost (swing fuel), revenue requirement and system average rate.

Step 2. Calculate resale rates and associated revenue requirement.

Step 3. Calculate the indexed rates and revenue requirement (G-50, G-58, and G-59).

Step 4. Set G-55 and G-57 rates at PG&E's contract fuel oil price (53.948 cents/therm).

Step 5. Increase the average G-1 and G-2 rates by equal percentages until G-2 equals the G-50 rate plus 5% and which with G-1 equals the revenue requirement.

IX. FINDINGS AND CONCLUSIONS

A. Findings of Fact

1. The adopted results of operations for test year 1984 and each element thereof, as set forth in this opinion, provide a proper and reasonable basis for determining PG&E's California jurisdictional base-rate revenue requirement.

2. The proper and reasonable level of PG&E's California jurisdictional base-rate revenue requirement for 1984 is $3,350,529,000.

3. Present base-rate revenues are estimated to produce $2,999,551,000 in 1984.

4. The level of gross revenues produced by PG&E's present base rates for electric service will not recover PG&E's revenue requirement in the test year 1984.

5. A return on equity of 15.75% is fair and reasonable for the test year 1984 and attrition year 1985.

6. A 12.45% rate of return for the test year 1984 and a 12.53% rate of return for the attrition year result from the following capital structure and capital costs, which are fair and reasonable:

	Capital Ratio	Cost	Weighted Cost
	%	%	%
Test Year 1984			
Long-Term Debt	44.00	10.22	4.50
Preferred Stock	13.75	9.44	1.30
Common Equity	42.25	15.75	6.65
Total	100.00%		12.45%
Attrition Year 1985			
Long-Term Debt	44.00	10.37	4.56
Preferred Stock	13.75	9.57	1.32
Common Equity	42.25	15.75	6.65
Total	100.00%		12.53%

7. Projected costs of new debt issuances of 12.5% for 1984 and 1985 are fair and reasonable.

8. To earn an average rate of return of 12.45% in 1984, PG&E's base rates for California jurisdictional service should be increased effective January 1, 1984 to provide an increase in base-rate revenues of $219,934,000 for the Electric Department and $78,787,000 for the Gas Department, and should be further increased effective January 1, 1985 to provide for an attrition allowance to cover additional increases in cost of service for 1985.

9. The rate of return on rate base together with the other components of the increased base-rate revenue requirement are found to be justified and are authorized with the understanding that under the Rate Case Plan, the next earliest test year to be used for establishing PG&E's revenue requirement will be 1986.

10. For labor escalation it is reasonable to use the factors resulting from the August 30, 1983 settlement between PG&E and the labor union.

11. The general rate case is not the appropriate proceeding to resolve technical differences on nonlabor escalation rates. Much work remains to be done in this area. The utilities and staff should schedule workshops so that existing staff-utility disputes can be aired.

12. It is reasonable to use the WPI-IND for calculation of historical escalation since this is consistent with past practice.

13. A company-specific approach in developing a nonlabor escalation factor is useful but only if such approach is simple, relies on publicly-available sources and can be verified by staff and other parties.

14. A composite nonlabor escalation factor must reflect a reasonable weighting factor for non-utility labor.

15. The WPI-IND is a broad index which includes costs unrelated to utility operations.

16 The MPPI better reflects utility operations in part since it excludes certain costs unrelated to utility operations.

17. For nonlabor escalation it is reasonable to use a composite factor based on staff's MPPI reweighted to include a 30%, instead of a 5% weight for the CPI-W.

18. In determining PG&E's level of expenses in 1984, compounded rates of escalation since 1981 of 25.55% for labor and 11.32% for nonlabor are reasonable. Compounded escalation rates of 33.71% for labor and 17.7% for nonlabor in 1985 are also reasonable.

19. The adopted sales, revenues, expenses, plant and rate base estimates are reasonable for test year 1984.

20. PG&E's request to change current policy to allow expense treatment of preconstruction costs should be denied since adoption of this proposal would result in shifting the entire risk of abandoned projects to the ratepayer.

21. Under used and useful principles, ratepayers bear only the costs of those projects which become operational. Shareholders bear the full costs of abandoned projects.

22. It is reasonable to adopt the staff-recommended accounting treatment for feasibility studies as modified by this decision.

23. It is reasonable to allow PG&E to recover the direct costs of feasibility studies for 26 abandoned projects, as exceptions to used and useful principles, because of the extraordinary and unpredictable changes in circumstances which occurred during the period the projects were begun and later abandoned. PG&E will not recover any AFUDC. This treatment provides a fair and reasonable sharing of abandoned project costs between the ratepayer and shareholder. The direct costs will be amortized over four years and there will be no rate base treatment of the unamortized balance.

24. It is reasonable to exclude the Mendocino, Montezuma, South Moss Landing and Pittsburg 8 & 9 sites from Plant Held for Future Use (PHFU) since PG&E does not contemplate a specific and definite project at any of these sites.

25. The remaining gain from the sale of the Montezuma coal reserves not in rate base should be given to PG&E's shareholders and they should absorb the direct feasibility study costs and AFUDC.

26. If there is no reasonable prospect at the outset that a RD&D project involving tangible plant will become used and useful by becoming part of the utility's electric or gas operations, then the expenditures should receive expense treatment. Therefore, if the end result is knowledge, or does not involve tangible plant, the program costs should receive expense treatment. Otherwise, the cost should be capitalized.

27. The Cheng Cycle RD&D project costs should be amortized over two years, commencing in 1985, without carrying costs on the unamortized balance. It is reasonable to exclude equipment costs relating to this project from CWIP or rate base, should this equipment be used in conjunction with a commercial facility or RD&D project after completion of the Cheng Cycle project. It is also reasonable to deduct sale proceeds from revenue requirements if and when PG&E sells this equipment.

28. The Carrisa Plains Solar Power Project should not be funded by ratepayers, since there is great uncertainty as to the structure and financing of the project.

29. Since PG&E has improperly capitalized certain RD&D projects, only the direct costs related to these projects should be amortized over 4 years. No rate base treatment or carrying costs on unamortized balances is allowed.

30. It is reasonable to allow accumulation and ultimate recovery of AFUDC on prospective RD&D projects involving tangible plant as defined in Finding 26 if the utility has diligently and reasonably completed such projects.

31. The necessity for a utility to spend more than was authorized for any particular type of expense is a normal consequence of test year ratemaking.

32. In accordance with the policy set forth in Edison's last general rate case D.82-12-055 related to deferred maintenance, it is reasonable to reduce PG&E's request for test year 1984 O&M expenses by approximately $10 million, the amount requested for deferred maintenance.

33. The attrition allowance is not intended to compensate for every conceivable increase the utility may foresee for the attrition year. It is only intended as a reasonable allowance for the second year following a rate case. The attrition calculation set forth in this opinion provides such a reasonable allowance for 1985.

34. It is not reasonable to recognize growth in the attrition year without also recognizing productivity savings.

35. The O&M expenses requested by PG&E for Humboldt Bay Unit No. 3 are reasonable and should be included in the adopted expenses for the test year.

36. In preparing a long-term resource plan, it is reasonable to expect a utility to do a sensitivity analysis employing different economic assumptions. Only then can a least-cost strategy for additional generation be developed.

37. In view of the major uncertainties with respect to oil prices, it is reasonable to adopt a "wait and see" posture on conservation and load management programs and new capital intensive generation projects. This "hedging" strategy does not signal a retreat from the current level of promotion of cost-effective conservation, load management and alternative energy resources.

38. A major concern of the Commission continues to be the ability to monitor the impact of PG&E's Female-Minority Business Enterprise Program on the actual patterns of expenditures by PG&E for procuring supplies from female and minority business enterprises. Staff should continue to monitor the results of this program. In its next general rate case, PG&E should provide a report on its progress.

39. There is insufficient justification to adopt a franchise fee surcharge for San Jose and not for other cities within PG&E's service area. In its next general rate case, PG&E should address the question of separate surcharges for each city.

40. There is no basis to apply different ratemaking treatment to franchise fee expense increases resulting from arbitration decisions as opposed to court decisions.

41. Under test year ratemaking it is reasonable to deny recovery in the test year of additional franchise fees incurred prior to the test year.

42. PG&E may accrue in a memorandum account the increased franchise fees resulting from the pending Sacramento Superior Court decision and related settlements with other governmental entities based on the Sacramento decision, for amortization of reasonable costs in its next general rate case.

43. It is reasonable to allow ratepayer funding for EEI and AGA dues reduced by 25% for lobbying activities which do not benefit the ratepayer.

44. PG&E's Reliability Improvement Program is worthwhile and should be pursued cost-effectively to counter the adverse effect of aging, deteriorating steam plant.

45. The steam plant Reliability Improvement Program proposed by PG&E is too ambitious to allow prudent expenditure of the entire request within the test year. The staff recommended expenditure level of $47,825,000 is reasonable. In its next general rate case proceeding PG&E should provide a report on this program.

46. An allowance of $10.2 million to cover unforeseen expenses resulting from forced outages and unplanned maintenance of steam plant equipment is reasonable.

47. The mere fact that PG&E's linear trend for estimating O&M expense may have yielded a coefficient of determination (R-squared) greater than 0.6 does not necessarily mean that the trend produces reasonable results.

48. Other considerations besides the mechanical application of statistical techniques are relevant in arriving at a reasonable expense estimate.

49. Use of a five-year average in estimating maintenance expense may not fully capture the impact of aging and deteriorating plant on maintenance expense.

50. It is reasonable to base the funding provided in the test year revenue requirement for production, transmission and distribution expense on the trend of recorded expenditures over the last seven years.

51. Based on the CMP Audit it is reasonable to make an additional productivity adjustment of 4% for crew-related activities in transmission and distribution expenses.

52. The PCB transformer replacement program proposed by PG&E is reasonable and a revenue requirement of $4,009,000 and $5,942,000 for 1984 and 1985 respectively should be adopted.

53. The adopted production, transmission and distribution expense (O&M) is reasonable.

54. The adopted level of expenditure for O&M represents about a 25% increase over the 1982 authorized amount.

55. An amount of $500,000 is reasonable for PG&E to inform customers of the change from lifeline to baseline rates.

56. Amounts of $50,000 for the Read Your Own Meter program, $100,000 for the Plan Your PG&E Bill program and $150,000 for the Balanced Payment Plan program are reasonable.

57. Funding for PG&E to conduct community meetings is unnecessarily duplicative of public witness hearings.

58. PG&E is the only California utility which requires manual meter subtraction exercises, and which has not taken advantage of new meter reading technology.

59. It is reasonable to adopt half of the staff recommended adjustment for meter reading expenses.

60. If there is a known increase in postage expense in 1984, it is reasonable that this increase be reflected in the 1985 attrition allowance.

61. The adopted level of expenditure for customer accounts is reasonable.

62. It is not reasonable to reflect additional productivity savings related to A&G in the test year because many of the CMP audit recommendations are in the course of implementation or still need to be implemented.

63. PG&E should study the rapid increase in A&G expenses, and in its next general rate case proceeding should advise the Commission on the steps taken to control these expenditures.

64. It is reasonable to use a factor of 25% to allocate A&G expense to construction during the test year period, based on the factors used by comparable utlities.

65. It is reasonable in the area of A&G to determine expense levels and productivity savings on an account-by-account basis, rather than imputing across-the-board productivity savings.

66. For the account for A&G salaries, it is reasonable to base the adopted estimate on recent recorded expenditures, allowing for reasonable growth.

67. A 3% increase in A&G salaries over 1981 recorded expenditures is reasonable.

68. It is reasonable to base the adopted estimate for supplies and expenses on recent recorded expenditures.

69. An increase of 8% for office supplies and expenses in 1984 is reasonable because of PG&E's need to improve its computer cabability.

70. In estimating test year customer accounts expense it is reasonable to consider recorded 1981 and 1982 expenditures.

71. In adopting expense for customer awareness programs, it is reasonable to expect PG&E to inform customers at the lowest reasonable cost.

72. Recovery of EEO litigation expense should be based on the reasonable cost of each suit. These expenses should be included in the general rate case following settlement or conclusion of the proceeding. For ratemaking purposes, EEO expense should not be estimated on a prospective basis; therefore, it is reasonable to disallow the amount of $107,000 which staff identified as future EEO expenses.

73. A repair allowance of $35,354,000 is reasonable for test year 1984 for the purpose of calculating California corporate franchise tax.

74. It is reasonable to allow PG&E to establish a separate memorandum account for future recovery of the revenue requirement related to the TEFRA change to IRC Section 189.

75. The staff's recommended adjustments to AFUDC accrued during the years 1979 through 1982 are reasonable and should be adopted.

76. It is more appropriate to address the prepaid unamortized balance of all-risk insurance coverage for Diablo Canyon in the Diablo Canyon rate case proceeding.

77. PG&E's estimate for computer-related equipment included in common plant is excessive and should be reduced by 10%.

78. In its next general rate case proceeding, PG&E should quantify the additional productivity realized through the large increase in computer equipment provided for in test year 1984.

79. PG&E's proposed staffing of two operators per shift for pipeline operations is reasonable.

80. It is appropriate to base test year power costs for estimating the cost of electricity used to move gas into storage on the 1982 recorded rate of 74.2 mills/kWh.

81. PG&E's estimate of station expense is reasonable based on the addition of the Los Medanos Storage Field to operations.

82. It is not proper to allow PG&E to recover for past expenditures for gas losses.

83. The adopted estimates for gas production, transmission, and distribution expense are reasonable in that they reflect reasonable levels of growth over recent recorded expenditures.

84. The adopted expense estimates for customer accounts are reasonable in that they reflect less ambitious customer information-type programs which are funded at levels more consistent with historical expenditures.

84a. The adopted A&G expense estimate reflects reasonable levels of operation during the test period.

85. Commencing in 1984, PG&E should be authorized to add Account 823, Gas Losses, to those accounts in the Gas Adjustment Clause.

86. In its next general rate case proceeding, PG&E should provide a report on the progress made in its K Regulator Program.

87. Based on projections of energy prices, it is reasonable to fund conservation programs at levels comparable to those authorized and recorded in 1982 and 1983.

88. Conservation programs which appear ineffective should be canceled and new programs added to help customers who have had limited benefits from existing programs.

89. It is important to maintain the existing framework for cost-effective conservation programs in authorizing reasonable funding levels.

90. All but one of the conservation programs pass the participant, utility, and societal cost-effective tests.

91. All conservation programs fail the nonparticipant cost-effectiveness test.

92. The results of the nonparticipant test should be interpreted with caution and should not be relied upon exclusively in evaluating a given conservation program.

93. The staff's proposed adjustments to the Builder Conservation Program are warranted and should be adopted.

94. Expansion of incentives for second refrigerator removal and the purchase of high energy refrigerators beyond the amount requested by PG&E is not warranted.

95. Microwave oven incentives should not be funded. Furthermore, it is reasonable to discontinue the clothes dryer incentives in 1985 if they prove unpopular.

96. Because of poor customer participation and low PG&E expenditure levels in the past for the master meter conversion program, the adopted funding level is reasonable for this program.

97. It is reasonable to transfer the Community Service and Stockton Training Programs to the RCS and ZIP Programs.

98. It is not reasonable for PG&E to continue the recent trend to expend amounts substantially beyond those contemplated for energy management incentives.

99. Reductions in the Technical Support Program are reasonable because of substantial overlap with the programs it supports.

100. Staff's recommended funding level for Communications and Seminars is comparable to past expenditures and is reasonable.

101. Evaluation is a crucial component of conservation programs. Ongoing evaluation, and adjustments if warranted, are essential to maintaining the most cost-effective effort possible.

102. Conservation savings quantification results and the reasonableness of energy savings assumed for each program are essential evidence necessary to evaluate the reasonableness of conservation programs.

103. It is reasonable to carry over with interest unspent funds for conservation, load management, and the CVR and 12-21 kV conversion programs into the attrition year. Treatment of unspent funds with interest from the attrition year should be addressed in the next general rate case.

104. It is reasonable to base interest on unspent funds indicated in Finding 103 on one-half the 1984 end-of-year balance,

including encumbered but unspent funds, at the annual average short-term 90-day commercial paper interest rate.

105. It is reasonable to permit PG&E to reallocate up to $2.5 million to or from any program within each of the residential and nonresidential conservation program areas. Budget adjustments between the residential and nonresidential areas or adjustments in excess of $2.5 million shall be made the subject of an advice letter filing.

106. The adopted conservation program budget for 1984 included under customer service and information expenses of $46,860,000 is reasonable and does not include budgets for programs which are subject to separate proceedings.

107. Marketing service expenses recommended by staff are reasonable.

108. It is reasonable to fund load management at levels which continue cost-effective programs and fund new experimental programs.

109. Because of the absence of need for capacity in the 1980s, it is reasonable to expand cost-effective load management programs only when the capacity is needed.

110. PG&E has not spent the amount of load management funding authorized in 1982 and 1983.

111. It is doubtful that PG&E can effectively carry out the large number of experimental programs it requests to fund in the test year.

112. The success of load management efforts is not dependent only upon the number of load management hardware devices installed.

113. The next two years provide a unique opportunity for PG&E to make careful and thorough analyses of load management experiments which it has conducted to date.

114. Nearly all of the load management programs fail to be cost-effective to the nonparticipant ratepayer.

115. There is a need to evaluate whether load management incentive payments should be treated as transfer payments recovered through rate design or as program costs, as discussed in this decision.

116. Load and energy reductions and other input assumptions assumed for each load management program are essential evidence necessary to evaluate the reasonableness of load management programs.

117. The cycling option within the A/C Direct Control Program is not cost-effective and should not be continued.

118. It is reasonable to restrict expenditure of funds authorized for the A/C Direct Control Program to that program only.

119. The Water Heater Direct Control Program is not cost-effective and should not be continued.

120. It is reasonable to design Residential TOU rates to be revenue neutral.

121. It is reasonable to allow incremental metering costs associated with TOU meters to be absorbed in part by the participant.

122. Before accelerating the Residential TOU Program, it is reasonable to conduct a carefully controlled experiment to determine the program's overall cost-effectiveness.

123. By targeting the Residential TOU Program to customers in different climate zones, more representative data can be obtained.

124. It is reasonable to adopt cost-cutting measures, similar to those suggested by the CEC for the A/C Direct Control Program, for the Residential TOU Program.

125. Large-scale expansion of TOU load management programs for agricultural customers is not warranted until additional capacity is needed.

126. It is reasonable to redesign commercial and industrial loads management programs to improve their cost-effectiveness to the nonparticipant ratepayer.

127. It is reasonable to fund General and Support Programs at about $12.2 million to allow the acquisition annd evaluation of data obtained from specific load management programs.

128. It is reasonable to reduce the request for gas load management funding in order to be more consistent with recorded levels of expenditures.

129. The adopted load management budget for 1984 of $28,185,000 including both capital and operating expenditures is reasonable.

130. It is reasonable to permit PG&E to reallocate funds within the load management program of up to $2.5 million from a given program, except the residential A/C Control and TOU Programs, 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.

131. During 1982 and 1983 PG&E underexpended conservation and load management programs including interest on those expenditures in the amount of $22,996,000.

132. The 1982-83 underexpenditures in conservation and load management should be carried over and applied against 1984 revenue requirements.

133. An adopted research, development and demonstration budget of $32.3 million for 1984 is reasonable.

134. The staff's proposed adjustments to the RD&D request are reasonable.

135. PG&E requests funding for certain RD&D programs which appear to provide no special benefits to PG&E's service territory.

136. It is reasonable to reduce RD&D funding for activities generic to the utility industry and more appropriately conducted by national research organizations.

137. It is reasonable to reduce RD&D funding for activities to fund generic studies which relate to no specific project.

138. It is reasonable to provide funding to EPRI and GRI at the level established by each organization's actual billing to PG&E in 1983.

139. With some QFs, PG&E appears to have been less than careful in following the guidelines in D.82-01-103 for negotiating with QFs.

140. A program budget for conservation voltage regulation of $6,236,000 for 1984 is reasonable.

141. Program budget of $16.5 million for 1984 for the 12-21 kV conversion program is reasonable.

142. For rate-setting purposes, consumers should be signalled the present cost of consumption.

143. Short-run energy and short-run capacity costs are the correct way of conceptualizing marginal cost for rate-setting.

144. The adjustments to PG&E's resource plan adopted in this decision for the purpose of determining short-run energy and capacity costs are reasonable.

145. The short-run marginal costs can be calculated as operating costs plus shortage costs.

146. Shortage costs can be proxied by the capacity cost of a gas turbine, adjusted to reflect system reliability.

147. The Energy-Reliability Index (ERI) is flawed in that it is based on an imperfect match of two reliability criteria.

148. Since this imperfect match between the Loss of Load Probability and Expected Unserved Energy Criteria does not create a systematic bias, rejection of the ERI is not warranted.

149. The ERI discussed herein is an appropriate adjustment for the shortage costs at this time. Unadjusted shortage costs overstate the marginal cost.

150. Staff and interested parties should have access to PG&E's computer models used to calculate marginal costs.

151. Electric revenue allocation should be based on marginal costs.

152. Total effective revenue in rates should be allocated by marginal costs since it is the total rate which conveys the price signal to customers.

153. The modified EPMC method would shift a substantial amount of support for the baseline rate to other customer classes and would result in a residential average rate which deviates significantly from the system average rate.

154. The modified EPMC method is a departure from our practice in the last several rate case decisions and inconsistent with the policies adopted by D.82-12-113.

155. It is reasonable to shift gradually toward a full EPMC allocation method at this time, in view of the potential impact on certain residential users of an overall revenue increase combined with implementation of the baseline legislation.

156. A revenue allocation method of 95% SAPC-5% EPMC is consistent with the policies adopted in D.82-12-113 and reasonable at this time.

157. The system average percentage change (SAPC) method is a reasonable approach for offset rate cases because it is easy to apply and maintains a rate relationship established in the general rate case.

158. No marginal cost study was performed for the streetlighting class.

159. The streetlighting class should not be subject to marginal cost allocation.

160. Rate structure can affect the conservation of energy by consumers.

161. The three-tier residential rate structure contributes significantly to conservation.

162. Hardships resulting from the three-tier structure can be mitigated without elimination of the third tier. The baseline quantities established herein are reasonable.

163. The staff's proposal to set the size of the second tier such as it would contain an equal percentage of sales in each climate band is an equitable rate design.

164. In PG&E's next general rate case the company and staff should submit proposals to recalculate baseline quantities.

165. It is appropriate that the baseline rates be implemented on the date of the next seasonal lifeline rate change which is May 16, 1984.

166. Prorationing of bills during lifeline (baseline) seasonal changes is no longer necessary and should be eliminated.

167. The baseline quantities developed herein are reasonable.

168. Since residential hotels are similar to master-metered apartment buildings it is reasonable to extend the residential lifeline or baseline allowance to them.

169. A residential hotel is a hotel with at least 50% of its dwelling units under at least a one-month lease, and which units are occupied at least nine months of the year.

170. Time of Use (TOU) rates including residential TOU rates serve to meet short and long-term capacity needs.

171. TOU rates which are based on marginal costs ensure an economically efficient use of resources.

172. It is appropriate for TOU rates to reflect seasonal variations in utility marginal costs.

173. It is appropriate for voluntary TOU rates to be as revenue neutral as possible.

174. A master meter discount of $7.57 per space per month or electric master meter allowance is reasonable.

175. The electric master meter allowance should be applied on a flat-rate basis.

176. The electric residential rates discussed herein shown in the Rate Appendix B are reasonable.

177. The electric nonresidential rates discussed herein and shown in Rate Appendix B are reasonable.

178. The marginal cost of gas equals marginal operating costs plus shortage costs.

179. Gas marginal operating costs equal marginal acquisition costs plus marginal transmission costs.

180. The market clearing price equals the alternate price of fuel oil.

181. The short-run marginal cost of gas is equal to the greater of the marginal operating cost or the market clearing price.

182. It is appropriate for all customers to pay as close to the marginal cost of gas as possible as revenue constraints and minimization of uneconomic fuel switching allow.

183. PG&E's alternate price of fuel oil is the spot market price low sulfur fuel oil No. 6.

184. Gas rates should be based upon marginal cost.

185. Prorationing of natural gas bills at times of seasonal lifeline (baseline) changes is no longer necessary and should be eliminated.

186. The staff's recommended baseline quantities for gas for combined multi- and single-family use are reasonable.

187. The implementation date for gas baseline rates should be May 16th.

188. It is reasonable to change the residential rate structure from a three-tier to a two-tier structure because the marginal gas cost is below the system average rate.

189. Master meter discounts for gas should be handled in the same manner as electric master meters discussed previously.

190. Gas rate design guidelines discussed herein are reasonable.

B. Conclusions of Law

1. PG&E should be authorized to file the revised electric rates which are set forth in Appendix B and which are designed to produce $219,934,000 for the Electric Department and $78,787,000 for the Gas Department in additional revenues based on the adopted test year 1984 results of operations.

2. PG&E should be authorized to file revised electric rates designed to produce additional base rate revenues in the attrition year 1985 based on our adoptd ARA mechanism as set forth in this opinion.

3. PG&E should be authorized to file revised gas rates as set forth in the concurrent decision on PG&E's A.83-08-38 GAC proceeding which include the additional base rate revenue authorized in this proceeding.

4. PG&E should be authorized to file revised gas rates designed to produce additional base rate revenues in the attrition year 1985 based on our adopted ARA mechanism set forth in this opinion.

5. All transcript corrections received are incorporated in the record.

6. All motions not specifically ruled upon are denied.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is authorized and directed to file with this Commission, on or after the effective date of this order, revised tariff schedules for electric rates as set forth in Appendix B attached hereto and by this reference made a part hereof.

2. PG&E is authorized and directed to file with this Commission, on or after the effective date of this order, revised tariff schedules for gas rates as set forth in the concurrent

decision on PG&E's A.83-08-38 Gas Adjustment Clause (GAC) proceeding which includes the additional base rate revenue authorized in this proceeding.

3. The revised tariff schedules shall become effective on the date of filing but not earlier than January 1, 1984, and shall comply with General Order 96-A.

4. The revised rate schedules shall apply to service rendered on or after the effective date of the revised tariff schedules.

5. PG&E shall inform the Commission of the proceeds from a sale of the gas turbine which forms part of the Cheng Cycle demonstration project. PG&E shall also notify the Commission if and when any of the Cheng Cycle equipment is used in conjunction with a commercial facility. Such equipment costs shall be excluded from any CWIP account or rate base associated with a commercial facility.

6. PG&E shall indicate in its next ERAM proceeding whether or not the $6.3 million ratepayer refund ordered by the Commission in D.82-12-113 was applied correctly.

7. PG&E shall comply with the reporting requirements set forth in Appendix A of this decision.

8. PG&E shall comply with staff's recommendations regarding future RD&D filings and annual reports as set forth in this decision.

9. PG&E shall carry over with interest unspent funds for conservation, load management, and the CVR and 12-21 kV conversion programs into the attrition year. Interest shall be calculated as set forth in Finding 104.

10. Reallocation of conservation and load management funds to or from the major categories or reallocation in excess of $2.5 million to or from individual programs shall be made the subject of an advice letter filing. Such reallocations shall be consistent with Findings 105 and 130 of this decision.

11. PG&E shall file a plan within 30 days of the effective date of this decision which applies the lifeline or baseline allowance to residential hotels as defined in this decision. In its plan PG&E

shall indicate how it intends to identify residential hotels (e.g. self-certification) and to what extent it intends to coordinate its plan with local governments and organizations.

12. PG&E shall file by advice letter within 60 days of the effective date of this decision, new residential TOU rate structures as discussed in this decision.

13. PG&E shall file by advice letter no later than April 1, 1984 more appropriate penalties for failure to curtail under rate Schedule No. A-23, as discussed in this decision.

14. PG&E shall allow staff and interested parties access to its computer models used to calculate marginal costs.

15. In PG&E's next general rate proceeding, it shall provide the following:

a. A sensitivity analysis in its long-term planning exhibit, and an explicit demonstration of how the estimated costs of the resources available to the utility and the utility's preferred resource plan combine to formulate a least-cost strategy for additional generation in the future.

b. A progress report on PG&E's activity in increasing participation of female and minority business enterprises in the procurement of PG&E's goods and services.

c. A review of the practical and administrative problems of implementing a proposal to apply franchise fee surcharges to customers of the city which imposes them.

d. A presentation of levels of wages and salaries estimated by the utility for comparison with similar wages and salaries paid in the marketplace.

e. An exhibit setting forth details of the improvements completed, actual expenditures and a cost-effectiveness analysis, including improvements achieved in heat rates as a result of PG&E's Reliability Improvement Program.

f. A full report on the electronic meter reading system and its implementation, including costs and quantifiable savings.

g. An exhibit reflecting CMP recommendations implemented and savings realized due to productivity gains. PG&E shall also provide an expert witness who will address the question of measuring productivity gains in the administrative and general (A&G) funding area, and steps taken to arrest rapidly escalating A&G expense.

h. An accounting of computer equipment purchased and the quantifiable savings which have been achieved.

i. A report on the cost and effectiveness of the K-Regulator Program.

j. An exhibit explaining the results of conservation and load management savings quantification, and the reasonableness of the energy and load savings assumed for each program.

k. An exhibit exploring to what extent load management incentive payments should be included in revenue requirements instead of being treated as transfer payments.

l. An exhibit explaining which marginal fuel price should be used in evaluating QF power, conservation, and load management.

m. A proposal for recalculating baseline quantities.

This order is effective today.

Dated December 22, 1983, at San Francisco, California.

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
PRISCILLA C. GREW
DONALD VIAL
WILLIAM T. BAGLEY
Commissioners

I dissent in part.

/s/ PRISCILLA C. GREW
Commissioner

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY.

Joseph E. Bodovitz, Executive Director

APPENDIX A

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REPORTING REQUIREMENTS FOR LOAD MANAGEMENT PROGRAMS

I. RESIDENTIAL (SCHEDULE NO. D-7) TIME-OF-USE PROGRAM

Pacific Gas and Electric Company will institute the recordkeeping and reporting procedure described below.

The information required by this reporting procedure shall be filed with the Commission on the 15th day of each month.

One copy of the report is to be filed with the Energy Conservation Branch of the Utilities Division.

Description of Required Records:

1. Each customer served under Schedule No. D-7 shall be assigned an identifying number and code which shall be used for the purpose of this reporting procedure. This number may not be changed. Customers whose time-differentiated consumption is monitored following the date of this order shall be identified as such.

2. Customers eligible to be served and those actually served under Schedule No. D-7 shall be grouped in accordance with their subgroups determined by lifeline allowance, zones, and districts, e.g. DITE, DITW, etc. These groupings shall be referred to as subgroups.

3. Each month (on the 15th) the utility shall provide a current list (or matrix) of customers grouped as described under paragraph 2 above for the preceding month. New customers shall be identified on these lists.

4. For each subgroup of customers whose time-differentiated consumption is measured, whether they are served under the TOU rates or not, the following data shall be provided. These data shall be brought up to date in each reporting period. Data for customers served under TOU rate shall be shown separately from those who are not yet served under the TOU rates. Data shall be shown for the years 1982 and 1983 based on reconstruction of billing records.

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a. The frequency distribution of the customers whose time-differentiated consumption is measured with respect to their total energy (in intervals of 50 kW) and the percent of their total energy consumption used on-peak (in intervals of 1%). The distributions shall be shown both on a chart (energy versus percent energy on-peak) and in a tubular form. The Commission staff may prescribe other intervals.

b. The frequency distributions with respect to the total energy consumption of all subgroups of customers eligible for service under the TOU rates (in intervals of 50 kWh or as prescribed by the Commission staff).

c. The frequency distribution with respect to the total energy consumption of all subgroups of residential customers (in intervals of 50 kWh or as prescribed by the Commission staff).

5. For each month (in each year) for which data are reported the utility shall provide the number of degree days and other climatic information relevant to weather-related trends, and other weather-related information that the Commission staff may prescribe.

6. For each subgroup of customers the utility shall calculate and provide the total amount of charges to the customers based on the metered consumption for the reporting month made under Schedule No. D-7 and the total amount of charges based on the metered consumption under the subgroup of the residential Schedule D-1 for which they would otherwise qualify. The Commission staff may require additional information concerning comparison of charges based on meter consumption.

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7. For each subgroup of customers served under the time-of-use Schedule No. D-7 the utility shall randomly select a control group of customers with the same eligibility criteria as the subgroup served under Schedule No. D-7. The number of the customers in each subgroup shall be such that the level of confidence for statistical comparisons shall be at least 95%. Time-differentiated energy consumption for the control groups shall be reported in the same manner as described above for the treatment groups or subgroups.

8. For each subgroup of customers served under the time-of-use rate Schedule No. D-7 the utility shall randomly select a subgroup of customers with the same eligibility criteria as the group served under Schedule No. D-7. The number of customers of these subgroups shall be equal to the number of customers in the subgroups served under Schedule No. D-7 or equal to a larger number prescribed by the Commission staff. For these customer subgroups (not on Schedule No. D-7) the utility shall report their total monthly energy consumptions and charges based on metered energy consumption in the corresponding month of the preceding year and two years ago. This information shall be tabulated to conveniently show the comparable values.

9. Records and information described in paragraphs 1 through 8 above shall be summarized for each six-month period and presented in the summarized form. These reporting periods shall coincide with the utility's billing seasons. These reports shall be due within 30 days of the end of each season (October 30, May 30) and shall contain all elements set forth in paragraphs 1 through 8. The Commission staff may require augmentation or modification of presentation of the information required by this appendix.

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II. NONRESIDENTIAL TIME-OF-USE PROGRAMS

In addition to the Annual Reports on Time-of-Use Rates for Very Large and Large Customers, the following data, presented in the manner specified below, shall be furnished:

This reporting applies (initially) to customers with billing demands higher than 1,000 kW. It will be extended at a later time to include all time-of-use schedules.

1. For each customer and for each billing period in a season as well as (where applicable) for the entire season show the following for each year since the start of the rate:
   a. customer identifier
   b. on-peak (billing) demand
   c. partial-peak demand
   d. off-peak demand (if available)
   e. on-peak energy
   f. partial-peak energy
   g. off-peak energy
   h. percent on-peak energy
   i. percent partial-peak energy
   j. percent off-peak energy (with respect to the total)

2. For each season and year show the relationship of on-peak billing demand as a function of energy consumption. This should be shown in the form of at least square fit curve (but the points should also be shown to present a display of the scatter).

   In addition, show:
   a. the distribution of the deviations from the least square fit curve
   b. divide the energy range in a suitable number of intervals (e.g. 10) and show for each of these intervals the distribution of deviations from the least square fit line
   c. evaluate if the distributions under (b) are energy dependent.

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3. Divide the percentages of time differentiated energy sales in two percent energy intervals. (Thus: 0 -2%; 2 - 4%; ...48 - 50%; ...98 - 100% off-peak; 0 - 2%; ...98 - 100% partial-peak.) These will be the consumption percentage cells used in data presentation. (Note that specifying the above two percentages determines the on-peak percentage as they all must add to 100%.) Show the number of customers in each of the consumption percentage cells. Show the distributions on a frequency plot with off-peak percentage shown as abscissa and partial-peak percentage as ordinate. Indicate also the equal on-peak consumption lines. The above should be done at least for each season but it is preferred that it be done for each billing period. (See attached figures.)

4. Show the differences between chronologically successive plots prepared under (3). The differences should be shown as increases (+n) or decreases (-n) in the number of customers in each consumption percentage cell.

5. The above information will be used to establish if an overall trend of customers toward higher (partial-peak off-peak) percentage cells exists: implying a decrease in the relative on-peak consumption.

III. ADDITIONAL COMMENTS

It is expected that implementation of the above will require additional retrieval and processing of utility billing date. Any problems should be brought to the attention of the staff without delay.

(END OF APPENDIX A)

APPENDIX B
Page 1

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Applicant's electric rates, charges, and conditions are changed to the extent set forth in this appendix. Base charge for PG&E includes revenue for Electrical Revenue Adjustment Mechanism (ERAM), Conservation Financing Adjustment (CFA), Solar Financing Adjustment (SFA) and Residential Conservation Services Adjustment (RCS).

Schedule No. A-100

This schedule is deleted. The existing California Public Utilities Commission Reimbursement Fee (CPUC Fee) is incorporated in the base rates adopted for each schedule noted herein.

Schedule No. DE

No Change

Schedule No. D1

Rates:

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Tier I, per kWh	0.04401	0.01127	.05528
Tier II, per kWh	0.04401	0.02781	.07182
Tier III, per kWh	0.04401	0.04932	.09333

	Per Kilowatt-hour		
	Tier I	Tier II	Tier III
Energy Cost Adjustment	0.00815	0.02469	0.04620
Annual Energy Rate	0.00312	0.00312	0.00312

Schedule No. DM

Rates:

	Per Kilowatt-hour		
	Tier I	Tier II	Tier III
Energy Cost Adjustment	0.00815	0.02469	0.04620
Annual Energy Rate	0.00312	0.00312	0.00312

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Page 2

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. DS

Rates:

The effective rates of the single family domestic service schedule, applicable in the territory in which the multi-family accommodation is located, except that the kilowatt-hours for Tier I shall be equal to the sum of the individual lifeline allowances for all residential dwelling units wired for service, the kilowatt-hours for Tier II shall be equal to two-thirds of Tier I, or 300 kilowatt-hours per kilowatt-hours per dwelling unit, whichever is greater, and a discount of $1.75 for each such dwelling unit shall be applied.

	Per Kilowatt-hour		
	Tier I	Tier II	Tier III
Energy Cost Adjustment	0.00815	0.02469	0.04620
Annual Energy Rate	0.00312	0.00312	0.00312

Schedule No. DT

The effective rates of the single family domestic service schedule, applicable in the territory in which the multi-family accomodation is located, except that the kilowatt-hours for Tier I shall be equal to the sum of the individual lifeline allowances for all residential dwelliing units wired for service, the kilowatt-hours for Tier II shall be equal to two-thirds of Tier I, or 300 kilowatt-hours per kilowatt-hours per dwelling unit, which ever is greater, and a discount of $7.57 for each such dwelling unit shall be applied.

Rates:

	Per Kilowatt-hour		
	Tier I	Tier II	Tier III
Energy Cost Adjustment	0.00815	0.02469	0.04620
Annual Energy Rate	0.00312	0.00312	0.00312

Schedule No. D7

Rates:

Customer Charge Deleted

Meter Charge $3.00 per meter per month

	Base Rates	Adjustments	Effective Rates
On-Peak, per KWh	0.04401	0.06655	0.11056
Off-Peak, per KWh	0.04401	0.01127	0.05528

	Per Kilowatt-hour	
	On-Peak	Off-Peak
Energy Cost Adjustment	0.06343	0.00815
Annual Energy Rate	0.00312	0.00312

APPENDIX B
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Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule Nos. D1, DM, DS, and DT

Effective May 16, 1984:

Lifeline terminology and allowances will be replace by the Baseline allowances adopted herein, and

Rates:

	Base Rates	Per Meter Per Month Adjustments	Effective Rates
Tier I, per kWh	0.04401	0.01103	.05504
Tier II, per kWh	0.04401	0.02707	.07108
Tier III, per kWh	0.04401	0.04779	.09108

	Per Kilowatt-hour Tier I	Tier II	Tier III
Energy Cost Adjustment	0.00791	0.02395	0.04467
Annual Energy Rate	0.00312	0.00312	0.00312

The base charges in the following schedules include the Annual Energy Rate(AER) as well as the adjustments mentioned in the opening paragraph.

Schedule No. A-1

	Per Meter Per Month
Customer Charge	Deleted
Minimum Bill	$1.75
Energy Charge, per kWh	$0.07807
Adjustments (included in Energy Charge)	
Energy Cost Adjustment, per kWh	0.02614
Annual Energy Rate, per kWh	0.00312

Schedule No. A-7 (New)

Meter Charge $3.75

Energy Charge	Per Kilowatt-hour
Base	$0.05236
Annual Energy Rate	0.00312

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Page 4

Pacific Gas and Electric Company

RATES -- ELECTRIC DEPARTMENT

Schedule No. A-7 (New) (Continued)

	Per Meter Per Month
Energy Cost Adjustments -	
On-Peak	0.04920
Mid-Peak	0.02957
Off-Peak	0.01198
Effective Rates -	
On-Peak	0.10181
Mid-Peak	0.08218
Off-Peak	0.06459

Schedule No. A-12

Customer Charge	Deleted
Minimum Bill	$20.00
Demand Charge	
First 40 kW, per kWh	Deleted
Next 260 kW, per kWh	Deleted
Over 300 kW, per kWh	Deleted
Per kW of maximum demand	$1.70

Energy Charge	Per Kilowatt-hour
Base	$0.03983
Energy Cost Adjustment	0.02614
Annual Energy Rate	0.00312
Effective Rate	0.06622

Schedule No. A-15

Customer Charge	Deleted
Minimum Charge, per LP	Deleted
Minimum Bill	$1.75
Energy Charge, per kWh	$0.12546
Adjustments (included in Energy Charge)	
Energy Cost Adjustment, per kWh	0.02614
Annual Energy Rate, per kWh	0.00312

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Pacific Gas and Electric Company
RATES - ELECTRIC DEPARTMENT

Schedule No. A-18 (Combined Current A-18A and A-18B)

Customer Charge	Deleted
Minimum Bill	$715.00
Demand Charge: On-Peak	Deleted
(A-18A) Off-Peak	Deleted

Energy Charge	Per Kilowatt-hour	
Base	$0.01861	
Annual Energy Rate	0.00312	
	Period A	Period B
Energy Cost Adjustments -		
On-Peak	0.03240	0.03240
Mid-Peak	0.02950	0.02950
Off-Peak	0.02283	0.02283
Effective Rates -		
On-Peak	0.05126	0.05126
Mid-Peak	0.04836	0.04836
Off-Peak	0.04169	0.04169

Schedule No. A-21

	Per Meter Per Month
Customer Charge	Deleted
Minimum Bill	$20.00
Demand, Per kW	
Period A	$1.70
Period B	$1.70

Energy Charge	Per Kilowatt-hour	
	Period A	Period B
Base	0.03809	0.03809
Annual Energy Rate	0.00312	0.00312
Energy Cost Adjustments -		
On-Peak	0.06317	0.04428
Mid-Peak	0.02160	0.02521
Off-Peak	0.01205	0.01851
Effective Rates -		
On-Peak	0.10151	0.08262
Mid-Peak	0.05994	0.06355
Off-Peak	0.05039	0.05685

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Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. A-21A (New)

	Per Meter Per Month
Customer Charge	Deleted
Minimum Bill	$20.00
Meter Charge	$10.00
Demand, Per KW	
Period A	$4.70
Period B	$1.70

Energy Charge	Per Kilowatt-hour Period A	Per Kilowatt-hour Period B
Base	0.03809	0.03809
Annual Energy Rate	0.00312	0.00312
Energy Cost Adjustments -		
On-Peak	0.06377	0.04428
Mid-Peak	0.02160	0.02521
Off-Peak	0.01205	0.01851
Effective Rates -		
On-Peak	0.10151	0.08262
Mid-Peak	0.05994	0.06355
Off-Peak	0.05039	0.05685

Schedule No. A-22 (Combined Current A-22 and A-23)

	Per Kilowatt-hour
Customer Charge	Deleted
Minimum Bill	$20.00

Demand Charges -	Period A	Period B
On-Peak, per kWh	Deleted	Deleted
Partial-Peak, per kWh	Deleted	Deleted
Per KW of Max Demand	$1.70	$1.70

Energy Charge	Per Kilowatt-hour
Base	$0.03724
Annual Energy Rate	0.00312

	Period A	Period B
Energy Cost Adjustments -		
On-Peak	0.05057	0.04684
Mid-Peak	0.03471	0.02738
Off-Peak	0.01262	0.01673
Effective Rates -		
On-Peak	0.08806	0.08433
Mid-Peak	0.07220	0.06487
Off-Peak	0.05011	0.05422

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Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. S-1

	Per Meter Per Month
Customer Charge	Deleted
Minimum Bill	$5.00
Standby Charge	
Co-generation & renewable Resources, per kWh	$0.80
All other service, per kWh	$1.00
Excess Off-Peak service, per kWh	- No change

Schedule BART

Traction Power	
Demand (Per kW)	No Change
Energy (Per kWh)	
Base	$0.03420
Annual Energy Rate	0.00312
Energy Cost Adjustment	0.02614
Effective Rate	0.06041
Station Power	
Demand (Per kW)	No Change
Energy (Per kWh)	
Base	$0.03420
Annual Energy Rate	0.00312
Energy Cost Adjustment	0.02614
Effective Rate	0.06041
Facility Charge	No Change

Schedule PA-1

Customer Charge	Deleted
Minimum Bill	$2.50
Demand Charge (Per kW of Max Demand)	
	Per Kilowatt-hour
Energy Charge	
Base	$0.03713
Energy Cost Adjustment	0.02614
Effective Rate	0.06352

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Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule PA-2

Customer Charge	Deleted	
Meter Charge (Per month)	$10.00	
Demand Charge (Per KW On-Peak Demand)	$8.00	
	Per Kilowatt-hour	
Annual Energy Rate	0.00312	
	Period A	Period B
Energy Charges - Base	0.03712	0.03712
Energy Cost Adjustments -		
On-Peak	0.06839	0.04883
Mid-Peak	0.02671	0.02894
Off-Peak	0.01732	0.01732
Effective Rates -		
On-Peak	0.10576	0.08620
Mid-Peak	0.06408	0.06631
Off-Peak	0.05469	0.05469

Schedule PA-3 (New)

	Per Meter Per Month
Customer Charge	Deleted
Meter Charge	$3.75
Energy Charges -	Per Kilowatt-hour
Base	$0.03953
Annual Energy Rate	$0.00312
Energy Cost Adjustments -	
On-Peak	$0.0610
Off-Peak	$0.01906
Effective Rates -	
On-Peak	$0.10079
Off-Peak	$0.05884

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Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule PA-R

	Per Meter Per Month	
Customer Charge	Deleted	
Meter Charge	$10.00	
Energy Charge	**Per Kilowatt-hour**	
	Period A	Period B
Base	0.03953	0.03953
Annual Energy Rate	0.00312	0.00312
Energy Cost Adjustments -		
Restricted On-Peak	0.11843	0.10420
On-Peak	0.04992	0.03968
Off-Peak	0.01434	0.01434
Effective Rates -		
Ristricted On-Peak	0.15821	0.14397
On-Peak	0.08970	0.07946
Off-Peak	0.05412	0.05412

Schedule No. OL-1

Rates:

	Per Lamp Per Month
Mercury Vapor Lamps	
175 Watts	$9.902
400 Watts	16.301
High Pressure Sodium Vapor Lamps	
70 Watts	7.514
100 Watts	8.623
200 Watts	12.630
	Per Kilowatt-hour
Base Energy Charge	$0.03898
Annual Energy Rate	0.00312
Energy-Cost Adjustment Rate	0.02614

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Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. LS-1

Rates:

Watts	A	B	C	D	E	F	Half-hour Adjustments
			Per Lamp Per Month				
Incandescent Lamps							
58	$8.578	-	-	-	-	-	$0.062
92	10.592	-	-	-	-	-	.097
189	12.99	11.209	-	-	-	-	.203
295	15.525	13.743	-	-	-	-	.315
405	18.247	-	-	-	-	-	.433
Mercury Vapor							
100	$7.73	-	6.722	-	-	-	$0.131
175	9.89	8.584	8.629	14.813	13.413	13.603	0.212
250	12.11	10.767	-	-	-	-	0.303
400	16.273	14.774	-	-	-	-	0.481
700	24.927	23.208	-	-	-	-	0.818
High Pressure Sodium Vapor							
70	7.509	6.752	5.278	11.175	9.292	8.194	.091
100	8.616	7.860	6.143	12.521	10.070	9.214	.128
150	9.866	9.110	7.513	14.391	11.690	10.584	.187
200	12.614	11.858	10.103	-	14.426	14.319	.281
250	14.610	13.853	11.512	-	15.840	15.728	.343
400	18.448	17.692	15.679	-	20.008	19.896	.521

Schedule No. LS-2

Rates:

Watts	A	B	C	D	E	F	Half-hour Adjustments
Incandescent Lamps							
92	2.272	4.962	6.332	-	-		.097
189	4.598	7.348	8.718	-	-		.203
295	7.059	9.879	11.249	-	-		.315
405	9.66	12.580	13.950	-	-	-	.434
620	14.655	17.705	19.075	-	-	-	.662
860	20.263	23.313	-	-	-	-	.918
Mercury Vapor							
100	3.024	3.504	4.474				.131
175	4.802	5.242	6.272	-	-	-	.212
250	6.787	7.327	8.387	-	-	-	.303
400	10.686	11.176	12.346	-	-	-	.481
700	18.075	18.895	20.305	-	-	-	.818
1,000	25.599	26.309	27.859	-	-	-	1.161

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Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. LS-2 (Continued)

Rates: Per Lamp Per Month

Watts	Volts	A	B	C	D	E	F	Half-hour Adjustments
High Pressure Sodium Vapor								
70	120 V	2.135	2.785	3.725	-	-	-	.091
100	"	2.956	3.626	4.586	-	-	-	.128
150	"	4.257	4.927	5.867	-	-	-	.187
70	240 V	2.478	3.148	4.098	-			.106
100	"	3.504	4.174	5.134	-			.153
150	"	4.294	5.610	6.550				.218
200	"	6.308	6.978	8.138	-	-	-	.281
250	"	7.676	8.356	9.716	-	-	-	.343
310	"	9.318	9.998	11.358	-	-	-	.418
400	"	11.576	12.256	13.596	-	-	-	.521
Low High Pressure Sodium Vapor								
35		1.725	-	-	-	-	-	.072
55		2.272	-	-	-	-	-	.097
90		3.639	-	-	-	-	-	.159
135		4.94	-	-	-	-	-	.218
180		6.103	-	-	-	-	-	.272
Metal Halide Lamps								
400		11.097	-	-	-	-	-	.499
1,000		26.283	-	-	-	-	-	1.192

Schedule No. LS-3

Rates:	Per Meter Per Month
Service Charge	No Change
Switching Charge	No Change
Energy Charge, per kWh	$0.06807

	Per Kilowatt-hour
Base Energy Charge	$0.03881
Annual Energy Rate	0.00312
Energy Cost Adjustment Rate	0.02614

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Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. TC-1

Rates:	Per Meter Per Month
Service Charge	Deleted
Minimum Charge*	$1.75
	Per Kilowatt-hour
Base Energy Charge	$0.04848
Annual Energy Rate	0.00312
Energy-Cost Adjustment Rate	0.02614

*The minimum bill shall be the minimum charge, plus adjustments for energy actually used.

(END OF APPENDIX B)

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List of Appearances

Applicant: Peter W. Hanschen, William E. Edwards, Michael S. Hindus, Gail A. Greely, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: John R. Bury, Charles R. Kocher, H. Robert Barnes, Susan L. Steinhauser, David N. Barry, III, Richard K. Durant, Frank J. Cooley, and Donald M. Clary, Attorneys at Law, for Southern California Edison Company; Thomas D. Clarke and Robert M. Loch, Attorneys at Law, for Southern California Gas Company; Biddle & Hamilton, by Richard L. Hamilton and Halina F. Osinski, Attorneys at Law, for Western Mobilehome Association; Thomas Vargo, for Robert Kihel, Naval Facilities Engineering Command; Bruce J. Williams, for San Diego Gas & Electric Company; Major Robert J. Boonstoppel, Attorney at law, and David A. McCormick, Attorney at Law (Pennsylvania), for Consumer Interest of U.S. Department of Defense and other affected Federal Executive Agencies; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr, Attorney at Law, for Nabisco Brands, Inc., General Motors Corporation, and Union Carbide Corporation; McCracken & Antone, by Michael D. McCracken, Attorney at Law, for California Street Light Association (representing California Cities and Counties); Brobeck, Phleger & Harrison, by Gordon E. Davis, William H. Booth, and Richard C. Harper, Attorneys at Law, for California Manufacturers Association, Kaiser Cement Corporation, and Natomas Company; Greve, Clifford, Diepenbrock & Paras, by Thomas S. Knox, Attorney at Law, for California Retailers Association; George Agnost, City Attorney, by Leonard Snaider, Deputy City Attorney, for City and County of San Francisco; Gary D. Fay and Gregg Wheatland, Attorneys at Law, for California Energy Commission; Graham & James, by James D. Squeri, Attorney at Law, for Graham & James; William L. Knecht, Attorney at Law, for California Association of Utility Shareholders; Walters, Bukey & Shelburne, by Diana D. Halpenny, Attorney at Law, for Schools Committee for Reducing Utility Bills (SCRUB); Sara M. Hoffman, for Contra Costa County; Donald H. Maynor, Attorney at Law, and W. R. Baldschun, for City of Palo Alto; Michael Peter Florio, Attorney at Law, and Sylvia M. Siegel, for Toward Utility Rate Normalization (TURN); Nancy R. Teater and William E. Swanson, for Stanford University; Anita P. Arriola, Attorney at Law, and Dan Becker, for Public Advocates; Jane S. Kumin, Attorney at Law, for Natomas Company; Mark R. Farman, for Resource Management International, Inc.; Stephen S. Slauson, for Independent Electrical Contractors of Alameda County; Harry K. Winters, for

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University of California; William B. Marcus, for California Hydro Systems, Inc. and Independent Energy Producers Association; John W. Krautkraemer, Thomas J. Graff, and David B. Roe, for Environmental Defense Fund; Craig Merrilees, for Campaign for Economic Democracy; Nicholas R. Tibbetts, for Congressman Douglas H. Bosco; Douglas M. Grandy, for State Government Energy Task Force; Matthew V. Brady, Attorney at Law, for himself; Antone S. Bulich, Jr., and Allen R. Crown, Attorneys at Law, for California Farm Bureau Federation; John R. Vickland, Attorney at Law, for San Francisco Bay Area Rapid Transit District; Barbara Kyle and Tim Sampson, for Citizens Action League and San Francisco Organizing Project; Wray Jacobs, for Service Employees Local 87; Evet Abt, Attorney at Law, R. J. Logan, and Rita Morton, for City of San Jose; R. O. Baish and Robert G. MacFarlane, for El Paso Natural Gas Company; Norman J. Furuta, Attorney at Law, for U.S. Department of the Navy; Lee Martin Lambert, for himself and Robert B. Innes; John T. Owens, for Williams Brothers Engineering Company; James F. Sorensen, for Friant Water Users Association; E. D. Yates, for California League of Food Processors; Wayne L. Meek, for Simpson Paper Company; Morrison & Foerster, by John M. Adler and Charles R. Farrar, Jr., Attorneys at Law, for United States Borax & Chemical Corporation; Hanna & Morton, by R. Lee Roberts, Attorney at Law, for Occidental Geothermal, Inc. and Ultrasystems, Inc.; John F. Powell, Attorney at Law, for Bay Area Air Quality Air Management District; Susan Rockwell, for U.S. Steel Corporation; Donald G. Salow, for Stone & Webster Management Construction, Inc.; Kevin B. Belford, Attorney at Law, for American Gas Association; Robert L. Baum, for Edison Electrical Institute; Nossman, Gunther, Knox & Elliott, by R. B. Spohn, for Applied Power Technology Institute; and Anderson, Hibey, Nauheim & Blair, by Virginia S. Carson, Attorney at Law, for Local Government Commission Inc.

Intervenor: Ann Miley, Attorney at Law, for International Brotherhood Electrical Workers Local 1245.

Commission Staff: Michael Day and Thomas Corr, Attorneys at Law, Bruce DeBerry, and Martin J. O'Donnell.

(END OF APPENDIX C)

APPENDIX D
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GLOSSARY

A.	Application
AB	Assembly Bill
ACC	Air-Conditioning Cycling
ACRS	Accelerated Cost Recovery System
ADR	Accelerated Depreciation Rate
AEI	Applied Energy Incorporated
AER	Annual Energy Rate
AFUDC	Allowance for Funds Used During Construction
AGA	American Gas Association
A&G	Administrative and General
ALJ	Administrative Law Judge
ARA	Attrition Rate Adjustment
APS	Arizona Public Service
ANGTS	Alaska Natural Gas Transmission System
AT&T	The American Telephone and Telegraph Company
Becker	Becker Large Plans
BLS	Bureau of Labor Statistics
BOY	Beginning of Year
BRRAC	Base Rate Revenue Adjustment Clause
Btu	British Thermal Unit

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GLOSSARY

C.	Case
CAM	Consolidated Adjustment Mechanism
CAUS	California Association of Utility Shareholders
CEC	California Energy Commission
CAPM	Capital Asset Pricing Model
C-I-A	Commercial-Industrial-Agricultural
CFA	Conservation Financing Account
CFB	California Farm Bureau
CCJCA	California Community and Junior College Association
CCFT	California Corporate Franchise Tax
COLA	Cost-of-Living Adjustment
CPI	Consumer Price Index
CPI-U	Consumer Price Index -- All Urban Workers
CPI-W	Consumer Price Index -- Urban Wage and Clerical Workers
CWIP	Construction Work in Progress
CVR	Conservation Voltage Regulation
CS&S	Computer System & Services
C/I	Commercial/Industrial
C/LM	Conservation/Load Management
CLMAC	Conservation Load Management Adjustment Clause
CMA	California Manufacturers Association
CMR-CMC	Class Marginal Rate-Class Marginal Cost
COLA	Cost of Living Allowance
CPUC	California Public Utilities Commission
CRA	California Retailers Association
CSER	Company Specific Escalation Rate
CT	Combustion Turbine
CFAG	Coachella Valley Association of Governments

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GLOSSARY

D.	Decision
DCF	Discounted Cash Flow
DRI	Data Resources Incorporated
DWR	Department of Water Resources
DSS	Demand Subscription Service
DFIS	Distribution Facilities Information System
DRI	Data Resources, Inc.
DWA	Direct Weatherization Assistance
ECAC	Energy Cost Adjustment Clause
Edison	Southern California Edison Company
EEI	Edison Electric Institute
El Paso	El Paso Natrual Gas Company
EPD	Equal Percentage of the Difference
EPRI	Electric Power Research Institute
ERAM	Electric Revenue Adjustment Mechanism
EPI	Equal Percentage of Increase
EPMC	Equal Percentage of Marginal Cost
ERAA	Electric REvenue Adjustment Account
ERTA	Economic Recovery Tax Act of 1981
FEA	Federal Executive Agencies of the United States
FIT	Federal Income Tax
Federal Agencies	Federal Executive Agencies
FERC	Federal Energy Regulatory Commission
F/MBE	Female Minority Business Enterprise
FUA	Power Plant and Industrial Fuel Use Act of 1978
GNP	Gross National Product
GAC	Gas Adjustment Clause
GCAC	Gas Cost Adjustment Clause
GEDA	Gas Exploration and Development Account
GRP	Generation Resource Plan

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GLOSSARY

Heber	Heber Binary Project
IEP	Independent Energy Producers
ICA	Insulation Contractors Association
IRC	Internal Revenue Code
IRS	Internal Revenue Service
IDB	Industrial Development Bonds
IRP	Intermediate Range Planning
ITC	Investment Tax Credit
IDC	Interest During Construction
kW	Kilowatt
kWh	Kilowatt-hours
LMRC	Long-Run Marginal Cost
LNG	Liquid Natural Gas
LOLP	Loss of Load Probability
L&P	Light and Power
MPPI	Modified Producer Price Index
NOI	Notice of Intention
OCR	Optical Character Reading System
OII	Order Instituting Investigation
O&M	Operation and Maintenance
P-5	Priority 5
PG&E	Pacific Gas and Electric Company
PGT	Pacific Gas Transmission Company
PPI	Producer Price Index
PHFU	Plant Held for Future Use
PGA	Purchased Gas Adjustment Clause
PACMAC	Policy Adjusted Class Marginal Cost
PT&T	The Pacific Telephone and Telegraph Company
PU	Public Utilities
PURPA	Public Utility Regulatory Policies Act of 1978

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GLOSSARY

QUA	Quantifying Added Uncertainties
QF	Qualifying Facility
RCS	Residential Conservation Service
RD&D	Research Development and Demonstration
R&E	Research Experimentation
SAM	Supply Adjustment Mechanism
SAR	System Average Rate
SDG&E	San Diego Gas & Electric Company
SCRUB	Schools Committee for Reducing Utility Bills
SONGS	San Onofre Nuclear Generating Station
San Diego	City of San Diego
SB	Senate Bill
SPP	Small Power Production or Small Power Producers
SFA	Solar Financing Account
SRMC	Short-Run Magrinal Cost
Staff	The Commission staff
SAPC	System Average Percentage Charge
Shareholders	California Association of Utility Shareholders
Sher Bill	Miller-Warren Energy Lifeline Act of 1975
SoCal	Southern California Gas Company
SRAM	Steam Revenue Adjustment Mechanism
SWAT	Southwest Area Transportation Planning Coordination Committee
TEFRA	Tax Equity and Fiscal Responsibility Act of 1982
Test Year	1984 Rate Case Year
TMI	Three Mile Island
Tr.	Transcript
TOU	Time of Use
TURN	Toward Utility Rate Normalization
T&D	Transmission and Distribution

APPENDIX D
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GLOSSARY

WMA	Western Mobilehome Association
WRO	Welfare Rights Organization
WAM	Weighted Average Method
WPI	Wholesale Price Index
WPI-IND	Wholesale Price Index for Industrial Commodities
WPISOP	Producer Price Index of Producers Finished Goods
ZIP	Zero Interest Program

(END OF APPENDIX D)

PRISCILLA C. GREW, Commissioner, Dissenting in part:

I dissent from the majority's decision on the treatment of the abandoned Mendocino project and the Montezuma property.

With regard to the Mendocino project, I am concerned about the justifications given in the majority's opinion for allowing recovery of associated costs. I agree that the economic and regulatory volatility as cited in the decision of the mid and late 1970s is a factor to be considered in determining the rate treatment of projects abandoned during this period. However, the Mendocino plant was abandoned in 1973. At that time, it was not the Commission's policy to allow recovery of such losses. The fact that PG&E waited ten years to request recovery suggests to me that the company did not originally expect ratepayer funding for these expenses.

I am also concerned about the rationale given that ratepayers should absorb costs because of their magnitude. This argument gives the unfortunate impression that the higher the losses are in an abandoned project, the more likely ratepayers will be charged with costs. In addition, the $13 million attributable to the Mendocino plant which is to be amortized over four years is not so extraordinary that it could not be borne by shareholders.

In the case of the Montezuma investment, the majority rejected an opportunity to apportion the gains between ratepayers and shareholders where ratepayers appeared to have assumed some of the investment risk. The appreciation of the non-rate base property was partly due to its relationship to be rate base property, an investment risk fully borne by ratepayers. Further, PG&E could have reasonably assumed that ratepayers would have shared the cost of failure, had it occurred, in light of our ratemaking treatment of other unsuccessful ventures in recent years. Because of these factors, a portion of the profit from the non-rate base property should have gone to ratepayers.

Priscilla C. Grew

PRISCILLA C. GREW, Commissioner

December 20, 1983
San Francisco, California