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ORIGINAL

Decision No. 89316 SEP 6 1978

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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| Application of Pacific Gas and Electric Company for authority, among other things to increase its rates and charges for electric service.<br>(Electric) | Application No. 57284<br>(Filed May 5, 1977;<br>amended June 15, 1977) |
| Application of Pacific Gas and Electric Company for authority, among other things to increase its rates and charges for gas service.<br>(Gas) | Application No. 57285<br>(Filed May 5, 1977;<br>amended June 15, 1977) |

(Appearances are listed in Appendix A.)

## INDEX

# O P I N I O N

Proceeding

Pacific Gas and Electric Company (PG&E) filed Applications Nos. 57284 and 57285 on May 5, 1977 which, respectively, request authority to increase its rates and charges for electric and gas service. The rates were designed to increase gross operating electric revenues by approximately 7.3 percent, or $161,402,000 annually, and gross operating gas revenues by approximately 8.8 percent or $130,758,000 annually, on a 1978 test year basis. Because these applications were filed while hearings were in progress on PG&E's general electric and gas rate increase requests, Applications Nos. 55509 and 55510, the Environmental Defense Fund (EDF) filed, on June 28, 1977, a "Motion To Dismiss" upon the grounds that the applications were premature and incomplete in light of the potential outcome of the pending applications.[1/] PG&E filed its response to EDF's motion on July 6, 1977.

1/ EDF filed a "Supplemental Brief in Support of Motion To Dismiss" on July 22, 1977.

By letter dated July 22, 1977 the Commission advised PG&E that:

> "...your above application numbers shall be deemed a Notice of Intention under the new Regulatory Lag Plan adopted by Commission Resolution No. A-4693 on July 6, 1977.
>
> "The Notice of Intention required thereunder shall be deemed filed on July 25, 1977. However, because your application was filed prior to the adoption of the Plan, it shall be processed as the first major utility general rate proceeding under the Plan. A copy of the NOI is required to be served on all appearances in the last general rate case within five days after the filing. Under the circumstances in your case, a general statement to all such appearances that the NOI has been deemed filed on July 25, 1977 will suffice. The 60-day period contemplated in the Plan shall commence on the filing date.
>
> "The staff has advised that the standard requirement list has been complied with except for the required conservation material. Because of the two pending matters relating to conservation programs, such draft exhibits relating to conservation effectiveness shall be filed not later than December 1, 1977. The application for general rate increase required by the Plan shall be deemed filed on September 25, 1977 and shall bear the same numbers that the pending applications bear. Your notice of filing of the NOI should contain the information regarding the application filing."

In accordance with the Regulatory Lag Plan, a duly noticed prehearing conference was held at San Francisco on October 4, 1977 before Administrative Law Judge Gillanders.

On October 20, 1977, PG&E filed a petition requesting a partial gas rate increase. On November 21, 1977 the staff filed its response to PG&E's petition recommending denial of PG&E's motion.

Public witness hearings were noticed and held at Red Bluff on November 8, at Stockton on November 9, at Fresno on November 15, and at San Francisco on November 16, 1977.

On December 5, 1977, PG&E filed its response to the staff's recommendation. On December 7, 1977, TURN filed its response to PG&E's request for a partial increase in gas rates.

On December 20, 1977 we issued Decision No. 88262 in Application No. 57556, Application No. 57642, and Application No. 57284.[2/] We ordered the following:

> "1. Application No. 57556 is granted on the basis of the results of operation shown in Table 14-A of Exhibit 4 at a 9.5 percent rate of return. The amount thus authorized is $71,178,000 as a partial rate increase in Application No. 57284.

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2/ Application No. 57556 for authority to implement a plan to stabilize electric rates and charges.

Application No. 57642 for authority to increase electric rates and charges in accordance with the energy cost adjustment clause.

Application No. 57284 for authority to increase rates and charges for electric service.

"2. For the 24-month period beginning January 1, 1978 all appropriate increases in base rates shall be offset by comparable dollar decreases in the Energy Cost Adjustment Clause (ECAC) rates and all appropriate reductions in rates shall be made.

"3. The monies collected in accordance with this order shall be subject to refund if found to be excessive by the final order in Application No. 57284.

"4. Pacific Gas and Electric Company (PG&E) shall maintain memorandum records to track the monthly increase in base revenue rates under the rate stabilization plan.

"5. PG&E shall apply any overcollection at a seven percent per annum interest rate against the ECAC balancing account.

"6. After the effective date of this order, PG&E is authorized to file the appropriate changes in base rates and ECAC rates as set forth in Appendix A attached to this order. Such filing shall comply with General Order No. 96-A. The effective date of the revised schedules shall apply only to service rendered on and after the effective date thereof.

"7. Application No. 57642 is dismissed."

Applicant's presentation commenced on December 13, 1977. Hearings were held on 37 days between December 13, 1977 and April 12, 1978.

On April 11, 1978, TURN filed a "Petition for Proposed Report". On April 14, 1978, PG&E filed a response to TURN's petition. The petition is hereby denied.

On May 1, 1978, the presiding officer issued an order reopening the evidentiary portion for the limited purpose of receiving written and oral comments and evidence of his proposed mechanism to eliminate the revenue effect of differences between test year electric sales estimates and actual sales experience (ECAM). Hearing was held on May 24, 1978.

Concurrent opening briefs were filed on May 12, 1978. Reply briefs and written replies to the May 1, 1978 order were filed on May 29 and the matter resubmitted.

The record contains 4,350 pages of transcript in 43 volumes and 164 exhibits.

General Information

PG&E is fundamentally a combination gas and electric utility. It also provides public utility water distribution service in 11 communities and steam sales service in a limited area of San Francisco where steam is used primarily for heating and cooling. It represents today a combination of more than 450 predecessor companies.

PG&E's gas business began with the San Francisco Gas Company, which was organized in 1852 as the first gas utility in the west and which introduced manufactured gas for lighting in 1854.

Electric service in the territory now served by PG&E commenced in 1879 when the California Electric Lighting Company began supplying series arc lighting service from a small central station in San Francisco, the first such station to be constructed in the nation.

Numerous competing gas and electric utilities were formed thereafter, both in San Francisco and in other cities and towns, with much duplication of facilities and intense rivalry for business. Out of uneconomic competitive wars came mergers and consolidations for greater efficiency and financial strength.

By 1896 the San Francisco Gas and Electric Company emerged with substantial but, at that time, expensive to operate steam electric generation capacity and an extensive manufactured gas system. In 1901 the California Gas and Electric Corporation was formed, consolidating several hydroelectric systems from which power was first brought into the Bay Area in that year. This company needed a wider market for its relatively low cost electric output.

PG&E was incorporated under California Law on October 10, 1905 to bring these two strong utilities together as the logical culmination of the long series of consolidations during half a century. This step gave San Francisco access to the lower cost hydroelectric power of the Sierra Nevada and provided steam capacity for firming the hydro generation.

For several years after its incorporation, PG&E operated as a holding company. In 1911, when it widened its direct ownership of utility properties, it became primarily an operating utility and has continued as such to the present time. The consolidation of San Joaquin Light and Power Corporation and Great Western Power Company into PG&E in 1930 and the merger with Coast Counties Gas and Electric Company in 1954 brought PG&E's service territory essentially to its present limits.

Natural gas was introduced into the San Francisco Bay Area in 1929. California sources were adequate for the continuous growth in demand until 1950 when the first out-of-state gas was obtained from El Paso Natural Gas Company. Additional supplies from Alberta, Canada were introduced in 1961. To provide for peak periods and improve operating efficiencies, above ground and below ground storage capacity was constructed in several strategic areas commencing in 1948. Storage operations were commenced at the McDonald Island underground storage field in 1958 and at the Pleasant Creek underground storage field in 1960. The natural gas supplies from all the foregoing sources continued to be adequate to meet the needs of PG&E customers until the end of 1972, when supplies began to decline, initially as a result of a Federal Power Commission (FPC) mandate. This decline of total supplies available to PG&E is expected by PG&E to continue for the foreseeable future. In order to partially relieve this decline by providing additional withdrawal capacity to meet firm peak demands, the McDonald Island well and pipeline facilities were greatly expanded during the period 1973 through 1976.

The basic 500 kv transmission network, which provides electric interconnections between PG&E and the power agencies in the Pacific Northwest and in southern California, became operational in 1968. Consisting of over 1,000 circuit miles, the Pacific Northwest Interconnection provides increased efficiency in the pooling of power resources between regions and companies and makes possible the delivery of surplus northwest interruptible power into PG&E's service area and the entire State. The interconnection has been expanded to carry power generated by the nuclear units being constructed at Diablo Canyon.

On December 31, 1976, PG&E's outstanding capital stock consisted of 88,610,337 shares of common stock, 35,098,025 shares of preferred stock, and there were 337,070 common stock and preferred stockholders.

Electric Service Area

PG&E distributes electric energy in 47 central and northern California counties to provide service to customers in 201 incorporated cities, many more unincorporated communities, and extensive rural areas.

The PG&E's inland electric service area extends from Coffee Creek in northern Trinity County and Bieber in northern Shasta County to Lebec in southern Kern County. In the coastal area electric service is supplied from Orick in northern Humboldt County to Las Cruces in southern Santa Barbara County.

This service area includes the metropolitan, industrial, and residential areas surrounding San Francisco Bay, the industrial and residential areas of the major cities and communities, and most of the agricultural regions of the central and coastal valleys. As of December 31, 1976, PG&E served a total of approximately 3,087,000 electric customers in all classes of service, including residential, commercial, industrial, agricultural, street lighting, resale, and others.

PG&E presently distributes electricity for resale by the following incorporated cities:

Lodi
Lompoc
Ukiah
Santa Clara

PG&E provides transmission service to the following incorporated cities:

Palo Alto
Redding
Roseville
Santa Clara

Gas Service Area

PG&E distributes natural gas in 39 northern central California counties to provide service to customers in 188 incorporated cities, numerous unincorporated communities, and scattered rural areas. Transmission facilities are located in two additional counties.

In the central valley region, the gas service area begins south of Bakersfield and extends northward to Redding. Service is provided to coastal areas from King City northward to Eureka and Arcata. Additionally, gas is served to desert area customers from the Topock-Milpitas transmission line in the eastern part of Kern County and in San Bernardino County.

The most concentrated distribution service is located in areas surrounding San Francisco Bay and to the cities in the Sacramento and San Joaquin Valleys. As of December 31, 1976 PG&E served a total of about 2,612,000 gas customers.

PG&E also supplies gas to the following utility companies for resale: California-Pacific Utilities Company (serving the city of Needles) and Southwest Gas Corporation (serving the cities of Barstow and Victorville).

Gas is also supplied by PG&E to the cities of Coalinga and Palo Alto which operate municipally owned gas distribution systems.

Associated Companies

PG&E's associated companies are:

1. Pacific Gas Transmission Company (PGT)
2. Pacific Transmission Supply Company (PTS)
3. Alberta Natural Gas Company Ltd. (ANG)
4. Alberta and Southern Gas Co. Ltd. (A&S)
5. Gas Lines, Inc. (Gas Lines)
6. Natural Gas Corporation of California (NGC)
7. Standard Pacific Gas Line Incorporated (StanPac)
8. Alaska California LNG Company
9. Pacific Gas LNG Terminal Company
10. Pacific Gas Marine Company

Pacific Gas Transmission Company owns and operates a natural gas transmission pipeline extending from the international boundary between Canada and the United States to the California border. The transmission company purchases natural gas from A&S, and transports the gas for sale at the California border to applicant. PGT also transports natural gas for Northwest Pipeline Corporation (NPC) for delivery to the Pacific Northwest.

The price of gas to applicant is based on a monthly cost-of-service tariff consisting of all operating expenses (including cost of purchased gas), depreciation, amortization, taxes (including applicable income taxes), and a return on rate base less charges to NPC for transportation service rendered and miscellaneous operating revenue.

Pacific Transmission Supply Company, a wholly owned subsidiary of PGT, was organized in December 1972 to carry out the Rocky Mountain Exploration Program. Some of the wells drilled as part of this program are considered to be potential commercial gas wells. PTS has applied to the FPC for authorization of sale of natural gas for resale in interstate commerce. PTS has entered into a gas purchase contract with PGT which provides for sale by PTS of its share of the production of natural gas in the Fontenelle Prospect in western Wyoming. The natural gas will be delivered to PGT based on a transportation and exchange agreement with NPC.

Alberta Natural Gas Company Ltd., a Canadian company, owns and operates a 36-inch pipeline from a point near Coleman, Alberta, to Kingsgate located on the British Columbia-Idaho border. It transports gas for both A&S and Westcoast Transmission Company Limited. It also owns and operates a liquid extraction plant near Cochrane, Alberta, which removes liquid hydrocarbons from the gas stream of A&S.

At December 31, 1976, PGT owned 44.87 percent of ANG's stock. Sales of stock have been made since October 17, 1972 to reduce PGT's ownership from 66-2/3 percent to 45 percent in order to allow greater participation by the Canadians in the ownership of ANG. No further sales are currently contemplated.

ANG is subject to regulation by the National Energy Board (NEB) of Canada. This board has the power to issue certificates of public convenience and necessity for the construction of pipelines beyond the limits of a province, and to make orders with respect to all matters relating to traffic, tolls, or tariffs of such pipelines.

Alberta and Southern Gas Co. Ltd., a Canadian company, is engaged in purchasing gas from producers in numerous gas fields in Alberta, Canada. The gas is transported to the United States border by ANG for delivery to PGT at that point.

Prior to January 1, 1975, the amount charged for gas delivered each month was based on the Gas Sales Contract between A&S and PGT. The charge was the greater of the specified price in the contract or the actual cost of service of A&S. Since January 1, 1975, the export price of natural gas from Canada has been wholly controlled by the Canadian government and has exceeded both the specified price in the contract and the actual cost of service.

Gas Lines, Inc. leases excess pipeline capacity from PG&E and uses this pipeline space to transport gas for nonutility gas producers in California.

The charges which the company pays to PG&E for the use of its facilities are set forth in an agreement between the companies. The charges are based on the volume of gas transported by Gas Lines for nonutility customers.

Natural Gas Corporation of California, acquired by PG&E n 1954, owns producing gas wells and is engaged in exploration development of natural gas lands. PG&E and NGC have agreed GC will conduct the gas exploration and development program

The Commission, in Decision No. 80878 dated December 19, lication No. 53118, authorized PG&E to advance $3,000,000 five years, for natural gas exploration with $1,500,000 be charged to exploration and development expense e added to investment in subsidiaries of PG&E. ration program are to be passed back to PG&E cost of gas.

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# CORRECTION

THIS DOCUMENT

HAS BEEN REPHOTOGRAPHED

TO ASSURE LEGIBILITY

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Natural Gas Corporation of California, acquired by PG&E in 1954, owns producing gas wells and is engaged in exploration and development of natural gas lands. PG&E and NGC have agreed that NGC will conduct the gas exploration and development program for PG&E. The Commission, in Decision No. 80878 dated December 19, 1972 in Application No. 53118, authorized PG&E to advance $3,000,000 per year, for five years, for natural gas exploration with $1,500,000 of this amount to be charged to exploration and development expense and $1,500,000 to be added to investment in subsidiaries of PG&E. Benefits of the exploration program are to be passed back to PG&E as a reduction in PG&E's cost of gas.

PG&E has not included the annual $1,500,000 exploration and development expenses in its operating expenses for purposes of the current general rate case. ✓

<u>Standard Pacific Gas Line Incorporated</u> is a California corporation which owns a pipeline. The company is a nonprofit private carrier of natural gas for the companies which own its stock, and is subject to the jurisdiction of the FPC. Applicant owns 85.7 percent (6/7) of the corporation's outstanding capital stock, and the remaining 14.3 percent (1/7) is held by Chevron USA (successor in interest to Standard Oil Company of California). The organization and management of the company are covered by an agreement executed in January 1961, which in essence provides that all costs and expenses are charged to the two stockholders in proportion to their interest in the company. For ratemaking purposes, 6/7 of StanPac's Plant-in-Service, Construction Work in Progress, and Materials and Supplies are included in rate base.

<u>Liquefied Natural Gas Companies - Alaska California LNG Company, Pacific Gas Marine Company, and Pacific Gas LNG Terminal Company</u>. PG&E formed three new wholly owned subsidiary corporations in February 1976 to facilitate its participation in joint liquefied natural gas (LNG) projects with Pacific Lighting Corporation (PLC). The three subsidiaries purchased equal partnership interests from PLC in three existing LNG projects.

PG&E's three LNG subsidiaries are now equal partners with three PLC subsidiaries in three partnership entities:

Pacific Alaska LNG Associates

Pacific Marine Associates

Western LNG Terminal Associates

Briefly, the division of LNG functions are:

(1) The purchase of natural gas and liquefaction of the gas for vessel transport.

(2) The transport of liquefied natural gas by special vessels.

(3) The receipt of the liquefied natural gas and regasification for transmission to consumers.

Results of Accounting Examination

Subject to its exceptions and recommendations,[3] it is the Finance Division's opinion that PG&E's accounting records and those of its regulated affiliated companies generally conform to the Uniform System of Accounts prescribed by the FPC and adopted by the California Public Utilities Commission, and that the accounting records of applicant's nonregulated domestic affiliated companies conform to generally accepted accounting principles.

3/ The exceptions and recommendations were incorporated into the staff's results of operation reports and will be discussed in following portions of this opinion dealing with rate base.

## Rate of Return

Any rate of return determination necessarily requires the weighing of a number of economic intangibles which are difficult to measure by statistical comparisons. It devolves upon the judgment of the Commission, after weighing the evidence presented by all of the experts, to determine and set a fair and reasonable rate of return. (Pac. Tel. & Tel. Co. (1968) 69 CPUC 53.) It was the testimony of PG&E's expert that a 15.0 percent rate of return on common stock equity or 10.33 percent rate of return on rate base is needed to enable PG&E to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

The Executive Agencies of the United States Government, using a discounted cash flow analysis, believe that 9.28 percent is a fair rate of return on total invested capital. The California Association of Utility Shareholders believes that to achieve actual average earnings of 13-1/2 percent to 14 percent will require a test year rate of return on average common stock equity of between 15.4 percent and 15.9 percent.

The staff's expert recommended a rate of return of 9.50 percent on rate base, or approximately 12.77 percent return on common stock equity.

The United States Supreme Court has established certain guidelines for ratemaking agencies in its determination of the just and reasonable rate of return to be allowed a public utility. These are contained in two cases: Bluefield Water Works and Improvement Company v West Virginia Pub. Service Commission (1923) 262 US 679, 67 L ed 1179, 43 S Ct 675 and Federal Power Commission v Hope Natural Gas Co. (1944) 320 US 591, 88 L ed 333, 64 S Ct 281. These cases establish that for a rate of return to be reasonable, it should be sufficient to allow a utility to compensate investors for risks undertaken, to attract capital, and overall to maintain its financial integrity. However, the Hope case further stands for the proposition that the interests of the investor must be balanced against those of the consumer.

In this decision, we have followed these guidelines while at the same time realizing that, although many tests and refinements may be used by rate of return witnesses, each case must ultimately be determined after considering all the evidence and that the Commission may exercise a considerable amount of discretion in determining what is a fair and equitable rate of return. (Pacific Tel. & Tel. Co. v P.U.C. (1965) 62 Cal 2d 634, at 656-58; Pacific Tel. & Tel. Co. (1968) 69 CPUC 53; General Tel. of California (1969) 69 CPUC 601; Southern California Edison Co. (1971) 72 CPUC 282.)

In Decision No. 88262 dated December 20, 1977 in PG&E's electric department, Applications Nos. 57556, 57642, and 57284 we said:

> "There still remains to be decided the basis upon which interim relief will be granted. The last PG&E general rate case was based on a 1976 test year and authorized a 9.2 percent rate of return and a 12.83 percent return on equity. The staff here has recommended setting permanent rates for the 1978 test year of 9.5 percent, but recommends maintaining the presently authorized 9.2 percent rate of return if the Commission authorizes the requested plan, while acknowledging that the 9.2 percent reduces the presently authorized 12.83 percent return on equity to about 12 percent, while the 9.5 percent should keep the return on equity at about the presently authorized level. We have in the past stressed the significance of the rate of return based on rate base. A closer analysis indicates that this figure is basically derived from the cost of capital required by the utility. Since the cost of debt and preferred stock is fixed and non-judgmental, the cost of equity capital (the return on equity) is the determination we are required to make which requires the most subjective and judgmental evaluation. From this, we arithmetically determine the rate of return on rate base. Thus, it is clear that the rate on equity is the major determinant of the just and reasonable rates we are required to produce. Since the last authorized rate on equity

> will be essentially maintained by the staff's permanent recommendation of 9.5 percent return on rate base, and since we are desirous of maintaining the status quo regarding the return on equity, we shall adopt the 9.5 percent rate of return to produce that stabilization we are adopting in this decision."

On May 16, 1978, we issued interim Decision No. 88835 in Case No. 10261 an investigation on the Commission's own motion into a natural gas supply adjustment mechanism (SAM), for gas utilities. PG&E was named as one of the respondents. In Decision No. 88835 we found the following:

> "2. Gas margin was defined as gross revenue less cost of gas at the test year level adopted in the last general rate proceeding.
>
> "3. Small deviations in actual sales from adopted test year sales may result in significant deviations from adopted test year gas margins.
>
> "4. Traditional ratemaking treatment of supply and sales has proven to be an inadequate method of considering the fluctuations described in Finding 3. Offset treatment between general rate proceedings is required."
>
> * * *
>
> "11. A SAM will reduce the risk to utility shareholders. That reduction in risk should be considered by the Commission in setting a reasonable rate of return in rate proceedings."
>
> * * *
>
> "13. Each gas utility should be authorized to implement a SAM balancing account effective on June 1, 1978. All gas utilities should be required to establish SAM balancing accounts on or before January 1, 1979."

In determining a fair return on common equity for these proceedings, we have considered the impact on risk derived from our adoption of Rate Stabilization and Energy Cost Adjustment Clause (ECAC) procedures for PG&E's electric department and the SAM and Purchased Gas Cost Adjustment Clause (PGA) for the gas department. We have also considered the fact that the Regulatory Lag Plan (applied to PG&E for the first time in these proceedings) worked extremely well.

These measures are designed to better allow PG&E to maintain a reasonably constant cash flow between general rate proceedings. These measures, however, must be viewed in the context of recent increases in inflation and upward trends in interest rates. But for these measures, it is likely that a higher return on common equity might be warranted to insure the financial health of the utility. Although, as mentioned, our innovative ratemaking measures impact risk downward, we do not find that in the balance (weighed against rising debt cost) a reduction in allowed return on equity is warranted.

Although we do not believe a downward rate of return adjustment based on inadequate conservation efforts is warranted at this time (as discussed in a following portion of this opinion), we think there are several areas of conservation endeavor and resource development in which PG&E has notably not been vigorous in its pursuit. Had PG&E vigorously pursued efforts to get cogeneration capacity on line, more aggressively undertaken its commercial and industrial energy audit program, and undertaken exhaustive review of repowering existing generating units as a resource option to building new capacity, and more aggressively promoted conservation, we would be inclined to authorize a higher return on equity in this proceeding.

Based on the above, it is our judgment that there is no need to increase the allowed rate of return. Maintaining the previously allowed 12.83 percent return on equity and the 9.5 percent return on rate base will be sufficient to allow PG&E to compensate its investors for their risks, to attract capital, and to maintain its financial integrity. It is also our judgment that such return on equity fairly balances the interests of the investor and the consumer in that the consumer will be supplied with dependable service and adequate supplies of both gas and electricity while the investor receives adequate compensation.

Our above discussion on rate of return emphasizing the importance of return on equity should put utilities on notice that, when faced with potential increases in customer demand, there may not always be a financial benefit to favoring options, including new plant construction, that expand rate base. We believe this should encourage utilities to seriously consider other options for expanding or improving service. More aggressive facility maintenance and modification efforts, including repowering, can increase plant output and reliability. Load management through rates and devices can improve load curves and reduce increases in peak demand. We will order PG&E to review its repowering options (including all hydroelectric facilities) and facility maintenance and modification efforts to determine additional cost-effective options, and to report its findings within 180 days (as a compliance filing in these proceedings).

Cogeneration is another alternative, and we repeat that we expect PG&E to pursue its considerable cogeneration potential aggressively. We do not believe PG&E has satisfactorily pursued the development of cogeneration capacity.

In addition, many utility customers, especially institutional users (e.g., schools, hospitals, the telephone utilities) have or may be planning standby auxiliary power sources for emergency use or cogeneration facilities. PG&E should, within 180 days, review and catalog all such existing and potential sources in its service area and their availability to contribute power during PG&E's high demand periods. PG&E should address the economies, institutional arrangements, maintenance and fuel requirements, and possible cost-effective incentives necessary to enable it to call upon such auxiliary facilities as peaking capacity for its system and report to the Commission on its findings within 180 days.

Our direction to review these options, which include additional sources of supply, is made in keeping with our often repeated observation that conservation very often represents the most cost-effective alternative for meeting a given level of demand. Where it is cost-effective against other alternatives, conservation investment represents the most efficient use of California's available capital (with minimum environmental impact) and should be encouraged over new generation. The Environmental Defense Fund (EDF) in its report entitled, "Alternative Energy Systems for Pacific Gas and Electric Company: An Economic Analysis", submitted in this proceeding, has done an admirable job of demonstrating the potential benefits to both ratepayers and shareholders of investments in conservation, as opposed to new plant, under various ratemaking scenarios. Concurrently, with this opinion, we are issuing an OII to further explore these ideas and alternatives.

Finally, there has been considerable discussion in this proceeding on the need for long-range electricity supply and investment planning and for such planning to include alternative sources of energy, including energy conservation. We agree that this need exists, and, furthermore, will order PG&E to make such supply and construction plans looking forward a minimum of 20 years. PG&E shall also make such plans publicly available.

Results of Operation Summary and Adopted

PG&E and the Commission staff have estimated PG&E's 1978 test year results of operation. Throughout the proceeding the staff accepted some of PG&E's expense estimates and PG&E accepted staff estimates. The following Table I shows the comparisons between final PG&E and staff estimates, for the gas department as well as our adopted test year results of operation. Tables II-A and II-B show the same comparisons and adopted results for the electric department.

TABLE I

Pacific Gas and Electric Company
Adopted Results
Gas Department

Results of Operation - Estimated Test Year 1978
(000's Omitted)

| | Staff | Utility | Present Rates | Authorized Rates |
|---|---|---|---|---|
| Operating Revenues | $1,612,957 1/ | $1,572,048 1/ | $1,572,048 | $1,671,377 |
| Operating Expenses | | | | |
| Total Production Expenses | 827 | 827 | 827 | 827 |
| Gas Cost | | | | |
| Balancing Account | 1,224,671 | 1,193,593 | 1,193,593 | 1,193,593 |
| PGT Transport Cost | 34,383 | 34,383 | 34,383 | 34,383 |
| Gas Department Uses | (9,560) | (9,560) | (9,560) | (9,560) |
| Total | 1,249,494 | 1,218,416 | 1,218,416 | 1,218,416 |
| Storage Expense | 2,827 | 2,957 | 2,869 | 2,869 |
| Transmission Expenses | 21,248 | 21,500 | 21,359 | 21,359 |
| Distribution Expenses | 53,700 | 56,240 2/ | 55,872 | 55,872 |
| Customer Account Expenses | 35,354 | 35,589 2/ | 35,589 | 35,589 |
| Uncollectibles | 2,158 | 2,103 | 2,103 | 2,236 |
| Customer Service and Informational Expense | | | | |
| Base Program | 3,793 | 3,793 | 3,793 | 3,793 |
| Supplemental Conservation | 7,474 | 7,474 | 7,474 | 7,474 |
| Total | 11,267 | 11,267 | 11,267 | 11,267 |
| Load Management Rate Research | 563 | 563 | 563 | 563 |
| Admin. and Genl. Expenses | 45,109 | 46,542 | 45,700 | 45,700 |
| Franchise Requirements | 9,439 | 9,200 | 9,200 | 9,781 |
| Wage Adjustment | 1,072 | 1,072 | 1,072 | 1,072 |
| Subtotal | 1,433,058 | 1,406,276 | 1,404,837 | 1,405,551 |
| Depreciation | 53,226 | 53,226 | 53,226 | 53,226 |
| Taxes Other then on Income | 44,806 | 44,806 2/ | 44,806 | 44,806 |
| State Corp. Franchise Tax | 2,251 | 932 2/ | 1,062 | 9,937 |
| Federal Income Tax | 1,632 | (4,762) 2/ | (4,138) | 38,937 |
| Total Oper. Exp. | 1,534,973 | 1,500,478 | 1,499,793 | 1,552,457 |
| Net Oper. Rev. Adjusted | 77,984 | 71,570 | 72,255 | 118,920 |
| Rate Base | 1,251,322 | 1,251,800 | 1,251,800 | 1,251,800 |
| Rate of Return | 6.23% | 5.72% | 5.77% | 9.50% |

1/ At present rates.

2/ Revised per p. 14, PG&E reply brief, income taxes recalculated.

TABLE II-A

Pacific Gas and Electric Company
Adopted Results
Electric Department
Results of Operation - Estimated Test Year 1978
(000's Omitted)

| | Total Electric | | | |
|---|---|---|---|---|
| | Staff | Utility | Adopted | Authorized |
| Operating Revenues | $1,184,392 1/ | $1,162,141 1/ | $1,162,141 1/ | $1,201,329 |
| **Operating Expenses** | | | | |
| Production Expense | 101,249 | 103,289 | 101,808 | 101,808 |
| Transmission Expense | 17,147 | 17,193 | 17,193 | 17,193 |
| Distribution Expenses | 108,982 | 110,648 2/ | 109,883 | 109,883 |
| Customer Account Expenses | 44,284 | 44,561 2/ | 44,561 | 44,561 |
| Uncollectibles | 2,203 | 2,162 | 2,162 | 2,234 |
| Customer Services and Informational Expense | | | | |
| Base Program | 6,479 | 6,479 | 6,479 | 6,479 |
| Supplemental Conservation | 6,655 | 6,655 | 6,655 | 6,655 |
| Total | 13,134 | 13,134 | 13,134 | 13,134 |
| Load Management Rate Research | 6,716 | 6,716 | 6,716 | 6,716 |
| Admin. and Genl. Expenses | 102,055 | 104,618 | 103,018 | 103,018 |
| Franchise Requirements | 6,455 | 6,334 | 6,334 | 6,547 |
| Wage Adjustment | 2,189 | 2,189 | 2,189 | 2,189 |
| Subtotal | 404,414 | 410,844 | 406,998 | 407,283 |
| Depreciation Expense | 167,080 | 167,080 | 167,080 | 167,080 |
| Taxes Other than on Income | 120,855 | 121,070 | 121,070 | 121,070 |
| State Corp. Franchise Tax | 23,808 | 21,054 2/ | 21,400 | 24,901 |
| Federal Income Tax | 82,770 | 69,322 2/ | 71,062 | 88,055 |
| Total Operating Expenses | 798,927 | 789,430 | 787,609 | 808,389 |
| Net Operating Revenues Adjusted | 385,465 | 372,711 | 374,532 | 392,940 |
| Rate Base | 4,165,699 | 4,182,965 | 4,182,965 | 4,182,965 |
| Rate of Return | 9.25% | 8.91% | 8.95% | 9.39% |

1/ At present rates.

2/ Revised per p. 14, PG&E reply brief, income taxes recalculated.

TABLE II-B

Pacific Gas and Electric Company
Adopted Results
Electric Department
Results of Operation - Estimated Test Year 1978
(000's Omitted)

| | Total Electric | | CPUC Jurisdiction | |
|---|---|---|---|---|
| | Staff | Utility | Adopted | Authorized |
| Operating Revenues | $1,184,392 1/ | $1,162,141 1/ | $1,120,567 | $1,159,755 |
| **Operating Expenses** | | | | |
| Production Expense | 101,249 | 103,289 | 90,128 | 90,128 |
| Transmission Expense | 17,147 | 17,193 | 13,318 | 13,318 |
| Distribution Expenses | 108,982 | 110,648 2/ | 109,423 | 109,423 |
| Customer Account Expenses | 44,284 | 44,561 2/ | 44,553 | 44,553 |
| Uncollectibles | 2,203 | 2,162 | 2,162 | 2,234 |
| Customer Services and Informational Expense | | | | |
| Base Program | 6,479 | 6,479 | 6,479 | 6,479 |
| Supplemental Conservation | 6,655 | 6,655 | 6,655 | 6,655 |
| Total | 13,134 | 13,134 | 13,134 | 13,134 |
| Load Management Rate Research | 6,716 | 6,716 | 6,716 | 6,716 |
| Admin. and Genl. Expenses | 102,055 | 104,618 | 100,945 | 100,945 |
| Franchise Requirements | 6,455 | 6,334 | 6,250 | 6,464 |
| Wage Adjustment | 2,189 | 2,189 | 2,153 | 2,153 |
| Subtotal | 404,414 | 410,844 | 388,782 | 389,068 |
| Depreciation Expense | 167,080 | 167,080 | 162,270 | 162,270 |
| Taxes Other than on Income | 120,855 | 121,070 2/ | 116,603 | 116,603 |
| State Corp. Franchise Tax | 23,808 | 21,054 2/ | 21,040 | 24,541 |
| Federal Income Tax | 82,770 | 69,382 2/ | 70,595 | 87,587 |
| Total Operating Expenses | 798,927 | 789,430 | 759,290 | 780,070 |
| Net Operating Revenues Adjusted | 385,465 | 372,711 | 361,277 | 379,685 |
| Rate Base | 4,165,699 | 4,182,965 | 3,996,682 | 3,996,682 |
| Rate of Return | 9.25% | 8.91% | 9.04% | 9.50% |

1/ At present rates.

2/ Revised per p. 14, PG&E reply brief, income taxes recalculated.

## Gas Department Results of Operation

### Operating Revenues

Revenue estimates are based on the level of rates which became effective July 12, 1977 in Decision No. 87585, a gas offset proceeding. PG&E's estimates have been adjusted to this rate level.

The staff's firm customer estimates were made by trending, considering recorded data through August 31, 1977.

The staff's estimates of customer sales by classes were developed utilizing PG&E's econometric model. The differences between the staff and PG&E involve the Consumer Price Index, Wholesale Price Index, marginal cost of gas, and nonagricultural employment in northern California. The staff estimates reflect recorded data for each variable through the first two quarters of 1977. PG&E's estimates are based on data through the third quarter of 1976.

The staff sales estimates reflect the effect of conservation. Recent conservation is reflected through the use of recorded data. For test year 1978, additional conservation has been reflected in specific adjustments due to appliances utilizing automatic ignition devices and for the effects of increased insulation because of revised building standards. In addition, residential consumption was correlated with a count of the number of residential buildings fitted with insulation.

The staff and utility requirement estimates show lower staff estimates for residential and commercial firm requirements and higher staff estimates for commercial and industrial interruptible requirements. The staff estimate reflects the transfer of a number of large customers from industrial interruptible to firm commercial schedules. As the staff has estimated a larger supply of available gas than PG&E, the staff's curtailment estimates are less. The staff estimates assume that all P-4 requirements will be satisfied and curtailment limited to P-5 customers. P-5 customers are Southern California Edison's Coolwater Plant and PG&E's Steam Electric Plants.

Staff adjustments representing higher gross revenues at both present and proposed rates are shown below:

| | Present Rates | Proposed Rates |
|---|---|---|
| Gas Supply | $73,626,000 | $79,285,000 |
| Staff Estimate of Firm Requirements Resulting in More Gas Available for Interruptible Requirements | 10,361,000 | 10,589,000 |
| Energy Content of California Gas | 1,097,000 | 1,181,000 |
| Imputed Rent | 79,000 | 79,000 |
| Total | $85,163,000 | $91,134,000 |

A witness for the General Services Administration (GSA) and the University of California (UC) testified that his estimate of PG&E's gas supply during 1978 was 776,030 M decatherms, or 5.86 percent higher than PG&E's estimate and 1.3 percent higher than the staff's estimate.

He made his projection of gas sales for residential, commercial, and industrial sales by using PG&E's year ended December 31, 1977, estimate of sales per customer times a different number of customers than PG&E estimated.

By adopting PG&E's sales estimate to residential customers, the staff's estimate of sales to commercial and industrial customers, and his estimate of gas supply, sales for steam electric purposes are increased almost to the staff estimate of 195,696 M decatherms. By this means, the gross revenue from gas sales can be increased. The differences between his estimate and those of PG&E and the staff are generally based on (1) different interpretations of regression analyses of recorded customers over the period of the last six years, (2) taking into account transfers from commercial class G-1 through G-9 schedules to the domestic class GS-1 through GS-9 schedules, and (3) the depressing effect of the PG&E econometric model on test year calculations of residential gas customers (households). His estimate of revenues from the gas department sales is $1,615,786,000. This is $87,992,000 more than PG&E's estimate and $2,829,000 more than the staff's estimate. We will adopt PG&E's gas supply and revenue estimate, which at present rates is $1,572,048,000 annually and $1,671,377,000 at the rates authorized herein.

Further, the staff's different projection of revenues is based on some assumptions which we are not sure will continue during the future period for which we are setting rates. First, the staff's estimate of residential demand is lower than PG&E's, and the staff assumes the gas which would otherwise be consumed by residential users will go to P-4 and P-5 customers, and the sales of additional gas to P-4 and P-5 customers would generate more revenue per therm sold. (That gas was priced by our rate design to be equivalent to alternative fossil fuel.) We believe the fluctuations in oil prices, particularly spot market oil purchase price, makes the staff's premise too speculative to rely on. If energy consumption and fuel choice trends and patterns were more solidified, we would be more comfortable with the staff's market relocation premise.

Likewise, we are not convinced that the estimate of UC and GSA is viable for ratemaking purposes. Given the tendency toward different usage patterns resulting from conservation consciousness and inverted gas rates, it is likely, in our opinion, that the witness for UC and GSA has not considered all the variables.

If we have misjudged in adopting our test year estimate of gas supply, the recent adoption of SAM (see earlier rate of return discussion) will insure that the utility's stockholders do not realize a windfall and that the ratepayers are protected.

Production (Cost of Gas) Expense

PG&E purchases 15.9 percent of its gas from northern California producers, 34.6 percent from El Paso Natural Gas Company (EPNG), which conveys gas for Texas and New Mexico producers, and 49.5 percent from PGT which imports gas from Canada.

The higher staff estimate of cost of gas is the result of its greater estimate of gas supplies. The greatest differences are in the California and El Paso volumes.

The staff estimate of energy content of California gas was obtained by trending the values for 1969 through 1976. The results are confirmed by the recorded monthly energy content of California gas for the first six months of 1977.

The staff assumed normal operations in which injections are equal to withdrawals.

PG&E and the staff estimate the cost of gas to be equal to the revenues embedded in rates to cover the cost of gas based on the sales estimate for Application No. 57285 and rates effective July 12, 1977. Embedded revenues represent that portion of the revenue received by PG&E which was allowed by the Commission to compensate for the cost of gas. This procedure was followed to coordinate the estimate of cost of gas for this proceeding with the gas cost balancing adjustment (GCBA) which will compensate for under- and overcollections.

PG&E estimates test year gas cost to be $1,218,416,000, which is $31.1 million less than the staff's estimate. The primary reason for this difference is that the staff estimated 4.1 percent more gas available to PG&E. Because we have adopted PG&E's estimate of sales, it is consistent to adopt the utility's estimate of gas expense (test year gas quantities available and revenues to be generated track).

Gas Storage Expense

PG&E's storage expense estimate for the test year exceeds the staff's by $130,000. This $130,000 difference results from different staff estimates for Accounts 816, 841, 834, and 845.

We believe PG&E's estimate of labor expense in Account 816, Wells Expense, and Account 845, Gas Holders, to be reasonable.

The staff used a trending approach to Accounts 841, Operation Labor and Expense, and 834, Compressor Station Equipment; PG&E based its estimate on 1976 recorded results. We believe for purposes of this proceeding that using an historical trend for these particular accounts is a better basis for projecting such expense for ratemaking purposes. Accordingly, we will adjust PG&E's estimate downward by $88,000, and adopt $2,869,000 for test year storage expense.

Gas Transmission Expense

PG&E's transmission expense estimate is $21.5 million. The staff proposes downward adjustments in this expense area totaling $252,000. PG&E's estimate for Account 853, Compressor Station Labor and Expense, should, as the staff proposes, be adjusted because the utility premised its estimate on 1976 recorded results. We adopted in the discussion on estimated revenues a conservative estimate of sales volumes. We think expense for this account may very likely be less than estimated by PG&E, given the specter of declining gas availability, and will adjust it by $141,000 as proposed by the staff.

The other proposed staff estimates for Accounts 850, 851, and 859 are not adopted because in our opinion PG&E has sufficiently justified the reasonableness of its estimates.

We adopt $21,359,000 for test year transmission expense.

Gas Distribution Expense

PG&E estimates test year gas distribution expense to be $56.2 million. The staff proposes an estimate of $2.5 million less.

The staff's estimate of Account 878, Removing and Resetting Meters, expense is $651,000 less than PG&E's. The staff trended cost for this activity on a unit per customer basis and arrived at a test year estimate of $2.58 per customer as a foundation for its estimate. Recorded unit cost per customer has fluctuated since 1972, and for both 1975 and 1976 it has remained at $2.70. PG&E's witness testified that labor costs have dropped since 1974 primarily because meter facilities were consolidated for efficiency, and that the transition period is over. We believe it is premature to accept the staff's trended estimate of this expense, given the stability during 1976 and 1977. The staff should review this expense area preparing for the next rate proceeding. At that time, it may be that a definite expense trend can be established.

The staff proposes that $91,000 less than PG&E's estimate be allowed for Account 878, Miscellaneous Meter Expense. PG&E based its estimate for 1978 test year expense on a combination of 1976 recorded results (for labor) and a 5-year average trend (for nonlabor). The staff considered the effects of automation occurring during 1977. We will adopt PG&E's estimate for this proceeding. If automation results in net expense savings for this account, the trend will be apparent in the future. At this time, we think the automation savings projected by the staff are still in the realm of a guess.

For Account 880, Other Expenses, the staff proposed an estimate $374,000 less than PG&E's original estimate. During the proceeding, PG&E agreed to the transfer of $239,000 in vacation pay accrual to its electric department. The remaining $135,000 difference is due to estimating methodology. We find PG&E's revised estimate to be reasonable.

In Decision No. 86281, Application No. 55509, we directed PG&E to study the feasibility of upgrading its maps and records procedures. The staff reviewed the results of the study, which concluded substantial savings could result from automating and centralization, and compared (on the electric side) PG&E's expense to Southern California Edison Company's. The conclusion reached by the staff is that PG&E can, if it implements the study's recommendations, save $1,154,000 in the test year (for both gas and electric departments). We are of the opinion PG&E should substantially implement the cost saving for its maps and records procedures. We believe it reasonable to adjust PG&E's estimate for Account 880, Maps and Records, by $1 million (total gas and electric) to reflect the savings it has the opportunity to realize in the future. Prorating this sum to the gas department results in an adjustment of $368,000. (A corresponding adjustment will be made to the electric department results of operations.)

The staff had a combined estimate for Accounts 886,887, and 892 totaling $911,000 less than PG&E's. The primary difference was due to estimating approaches. For purposes of this proceeding, we find PG&E's estimates for those accounts to be reasonable. We believe the staff's estimate of savings resulting from cathodic protection to be overly optimistic.

We adopt $55,872,000 as reasonable for gas distribution expense.

<u>Customer Account Expense</u>

PG&E's revised estimate of test year expense is $35.8 million. The staff differed with PG&E's estimate primarily because the staff projected no increase in postal rates.

In its reply brief PG&E acknowledges that its revised estimate for this account includes a one-cent discount for presorting first class mail, although the new postal rates actually provide a two-cent discount. (Reply brief, p. 14.) We will adopt PG&E's estimate and correct for the change in the discount. We therefore conclude that an estimate of $35,589,000 is reasonable for customer account expense.

<u>Uncollectible Expense (Account 904)</u>

PG&E and the staff used the same uncollectibles factor. The difference in their respective estimates is due to different revenue estimates. We adopt PG&E's uncollectibles estimate of $2.1 million at present rates because it is consistent with our adopting PG&E's revenue estimate. At authorized rates we estimate an amount of $2,236,000.

Customer Services and Information Expense

Originally the staff took exception with PG&E's estimate for this expense area (which includes base programs and supplemental conservation programs) and estimated $7.3 million less expense. Ultimately, during the proceeding, the staff's Energy Conservation Team witness accepted PG&E's estimate. The issue of conservation expense was put into these proceedings by Decision No. 88272, Application No. 56845 (December 20, 1977), which abolished the conservation expense offset balancing account procedure.

We have concern about $4,750,000 estimated expense for implementing an "insulation incentive" program whereby customers who had insulated attics could receive utility installed water heater insulation blankets and conservation shower heads. Although we directed implementation of that program by Decision No. 88551, Case No. 10032, rehearing has been granted and the program is deferred until our final resolution. However, PG&E's planned incentives programs relative to new ceiling insulation completions in the present application are different from those ordered in Decision No. 88551, and they should begin immediately. In the event that the planned programs are denied by any determination in Case No. 10032, the remainder of the $4.7 million should be applied to other conservation activities, in cooperation with the staff of the Energy Conservation Branch.

We adopt PG&E's estimate of $11.2 million as reasonable.

Administrative and General Expenses

PG&E's estimate for test year expense is $46.5 million. The staff's final estimate is $1.4 million less than PG&E's.

The staff's exceptions are with respect to Pension Expense, Account 926. It used a different estimating method for the number of new pension plan entrants, which would result in $747,000 less expense. Both the staff and PG&E extensively developed the record on this issue. We are of the opinion the utility did not fully support all of the estimated expense. However, we do not believe it reasonable to totally adopt the staff's estimate. We conclude that for this portion of Account 926 expense should be reduced by $500,000.

The remaining difference in this account totals $685,000 and relates to pension and benefits expense estimates associated with differences in direct labor expenses for various accounts. Because we have adopted some staff expense adjustments (which included labor expense), it is reasonable to concurrently adjust pension expense for consistency, and a reasonable basis to do so is to adopt half of the staff's proposed adjustment, or $342,000.

We conclude, based on the above discussion, that adopted test year administrative and general expenses should be $45.7 million.

Franchise Requirements (Account 927)

The staff and PG&E employ the same franchise expense factor, but the staff's estimate is $239,000 more than PG&E's because it is based on a higher gas department revenue estimate. Since we adopt PG&E's revenue estimate it is consistent and reasonable to adopt PG&E's franchise expense estimate of $9.2 million at present rates and $9,731,000 at authorized rates.

Depreciation Expense

Both PG&E and the staff estimated depreciation expense to be $53.2 million, which we will adopt.

Rate Base

The staff contends that the test year rate base should be $478,000 less than that proposed by PG&E. That difference is minuscule in view of a $1.2 billion rate base for the gas department.

The Finance Division as well as PG&E presented considerable testimony on the question of whether costs associated with a leasehold property known as Trico-Peny No. 3 (located in the Los Medanos gas field) were properly booked. PG&E contends that, if anything, the booked costs are too low and could be increased by $244,000. We believe that for purposes of this proceeding PG&E has demonstrated the reasonableness of the proposed test year rate base. The Finance Division may, of course, seek to better articulate the basis and foundation for this proposed adjustment in the next rate proceeding. In any event, as mentioned above, the effect of the staff's adjustment, if adopted, would be de minimis.

## Electric Department Results of Operation

Operating Revenues

The staff estimates used recorded data up to July 1977, while PG&E utilized recorded data which ended in November 1976. The majority of the differences between the staff and PG&E results from the availability of current data to the staff.

Historical data on customers and sales from 1961 through July 1977 were analyzed by the staff. Economic considerations such as inflation, recession periods, drought, and the O.P.E.C. oil embargo were all given consideration. In this analysis, PG&E's econometric model was used by the staff with the later data than those used in the original PG&E estimate. Past trends of customer growth and usage patterns were given careful consideration. In the final result, a judgmental decision was made by the staff of customers and sales by customer accounts.

A witness for GSA and UC testified that his estimate of average number of customers twelve months ended December 31, 1978 was 9,531 more than PG&E's estimate and 10,996 more than the staff's estimate. He estimated that PG&E underestimated its sales by 2,363 $M^2$ kilowatt-hours and the staff underestimated by 1,026 $M^2$ kilowatt-hours. Consequently, it was his estimate that the test year revenue should be $29,723,000 more than PG&E estimated because of its underestimate of customers and sales. He stated the staff revenue should be increased by $19,842,000 due principally to its underestimate of revenues from the domestic and medium lighting and power classes of customers.

We are concerned about an inconsistency in our ratemaking process when the element of requiring conservation effort is a major consideration. If an electric utility achieves good conservation results between general rate proceedings, it is in a real sense penalized, given existing regulatory procedures. The problem is simple: if conservation results, revenues decline, and the stockholder suffers. One possible solution is an Electric Conservation Adjustment Mechanism (ECAM), somewhat similar for SAM which we recently adopted for gas utilities; Decision No. 88835, Case No. 10261, dated May 16, 1978. Such a ratemaking procedure would allow for periodic rate adjustments, between adopted test year sales estimates, that would increase rates if sales declined, and reduce rates if sales exceeded the base (last Commission adopted test year) volumes. All other results of operations elements, such as expenses and rate base, would, when an adjustment is made, be held constant with last adopted test year levels. But we think it desirable to implement an ECAM procedure for electric utilities only after an investigation and full participation by all electric utilities and our staff. Although one day of hearing was devoted to the ECAM concept in those proceedings, we are of the opinion that the record was not sufficiently developed to implement an ongoing ECAM.

So, we are now back to our dilemma in this proceeding of selecting a test year sales volume on which to estimate revenues. PG&E's sales forecast is, in our opinion, more likely to be consistent with actual experience, given the impact conservation measures should have.

UC's witness compared the staff and PG&E estimates with recorded experience to arrive at his estimates. We do not think this approach is reliable for rate setting. It is based on data that are subject to distortion because of climatological irregularities. Also, it ignores changes in usage due to conservation efforts and rate design.

Production Expense

PG&E's estimate for total electric production expense is $103.3 million; the staff's is about $2 million less.

The staff proposes $417,000 less expense for Account 502, Steam Expense, because PG&E projected 1976 results (a drought year), whereas the staff applied a four-year average to represent a normal year. We believe the staff's approach will produce a more reflective test year estimate and will adopt it.

The staff also, in its estimate of total electric production expense (Account 507, Rents), arrived at $856,000 less expense as a result of investigating an oil storage contract with Urich Oil Company (Urich).

The staff takes exception to an agreement entered into in 1973 between the utility and Urich whereby Urich agreed to construct on its own property and operate four 1/2 million-barrel fuel storage tanks. The contract is for a 20-year period with termination only by mutual consent of both parties. Operating costs include depreciation and return on the actual cost of the tanks and actual costs on maintenance, operation, property taxes, and a number of other miscellaneous expenses. Each year Urich prepares a budget and this budget is approved by the utility. The contract provides for an audit by PG&E of all expenditures relating to construction, maintenance, or operation of the facilities.

The staff objects to PG&E's having entered into a 20-year contract when PG&E informed the staff that PG&E's needs were "short-term". Also, the staff contends that no formal economic study was made to justify the leasing of these tanks for 20 years. Further, the staff believes the company to be negligent in that it has not conducted any detailed audits to substantiate the original capital costs as well as the escalating annual costs. The staff recommends a decrease of $856,000 in the test year contract costs, and commencing January 1, 1980 all costs associated with the 1973 Urich lease should be excluded from operating expenses and treated as a below the line expense.

PG&E contends, primarily through its rebuttal witness, that this contract was a financially sound arrangement for PG&E; that PG&E's needs were well met by the 20-year term of the contract; that the Urich facility is a valuable addition to PG&E's storage system and will remain so into the future; that the increase in anticipated expenses was primarily for capital changes in the facility; and that PG&E is presently auditing the Urich contract expense and will be able to recover from Urich any excessive charges that may have occurred in the past. The utility contends the staff adjustment is unreasonable and that the full test year estimated expenses of $4,294,000 be allowed for this facility. It further asks that the staff's recommended disallowance be rejected.

We have reviewed the evidence, particularly PG&E's rebuttal testimony, and are satisfied that the agreement was a necessary one. Since it was necessary, we find the 20-year contract the result of good faith negotiations by the parties and therefore reasonable. What we are <u>not</u> satisfied with is the utility's explanation as to why no audits of cost were ever made (PG&E's testimony is silent on this point). Further, we are not at all satisfied that the current audit would have ever been undertaken if our staff had not brought this matter to our attention. PG&E's contention that, five years after the audits should have been started, it will now be able to go back and collect the excess charges of the past is, at best, naive.

In summary, we conclude that the agreement was reasonable at the time it was entered into and therefore we reject the staff's recommendation that all of the Urich costs subsequent to January 1, 1980 be below the line. We conclude that PG&E has been negligent in not auditing the costs. We will accept the staff's estimate of the test year expense for this facility as being more representative than the utility's based on the results of the staff's investigation.

The staff's estimate for Account 501, Fuel - Other, is $208,000 less than PG&E's. The staff used a "normal-year burn", whereas PG&E used a 1976 drought-year burn. This is an expense area where the utility will experience more incremental expense as more oil is handled. We will adopt the staff's estimate as more reflective of normal-year conditions.

We have reviewed carefully the staff's study on production expense. PG&E accepted many of the staff's original adjustments. The depth and scope of the study is impressive.

The staff's estimate for Account 540, Hydraulic Operations - Rent, is $163,000 less than PG&E's. The staff used a five-year average; PG&E used 1976 results, inflation adjusted. We find PG&E's estimate reasonable because it is more reflective of current conditions.

The staff estimated $300,000 less expense for maintaining generating facilities at Pittsburg Unit No. 7 (a relatively new plant), stating that PG&E's expense estimate was abnormally high compared to other units of similar vintage. We will not accept the staff's estimate, but we expect the staff to monitor closely the maintenance expense for that generating unit in the future, and report to us in the next proceeding on whether PG&E has succeeded in bringing its maintenance cost for this facility to a level comparable to its other more recently installed facilities.

PG&E's estimates for Accounts 511, 551, and 553 are reasonable because they project the most recent experience.

We adopt $101.808 million as test year total electric production expense.

Transmission Expense

PG&E's estimate for the transmission expense (total electric) is $17.2 million, which is only $36,000 more than the staff's estimate. The difference is in estimating procedures, and we conclude PG&E's estimate is reasonable. Originally the difference between the staff and PG&E was larger, but was narrowed by agreement during the course of hearings.

Distribution Expense

PG&E's estimate for total electric distribution expense is $110.6 million. The staff's estimate is about $1.7 million less.

The staff estimated $1.2 million less (total gas and electric) expense on the assumption PG&E could automate and modernize its maps and records (Account 880). This issue is discussed in detail in the preceding section on gas distribution expense. We will adopt $632,000 less than PG&E's expense estimate for this item, which reflects an appropriate allocation of expense savings to the electric department of the total anticipated $1 million savings.

The staff's estimate for Account 588, Miscellaneous Distribution Expense, is $379,000 less than PG&E's estimate. The difference results from different estimating approaches for nonlabor expense. PG&E used 1976 results projected for the 1978 test year. We believe PG&E's estimate will be more reflective of test year conditions and will adopt it.

Finally, the staff estimated $133,000 less expense for Account 593, Tree Trimming. The staff's contention is that PG&E's estimate does not reflect cost savings resulting from recently available growth-retardant chemicals and the trend toward undergrounding. We will accept the staff's test year estimate for this activity as more representative of future expense.

We will adopt $109.883 million as test year total expense for distribution expense.

Customer Account Expense

The staff proposed $277,000 less expense for mailing expense (see p. 14, reply brief). Originally PG&E estimated this expense to be $965,000 more than the staff's estimate; however, PG&E (in its reply brief) revised its estimate to reflect the actual amount of the recent postage increase to reflect the recent change to a two-cent presorting differential. We will adopt PG&E's estimates as corrected in the reply brief as being reasonable.

Customer Services and Information Expense

The staff analyzed PG&E's estimated expense for conservation and load management programs and found it reasonable. EDF, TURN, UC, and GSA questioned various specific conservation activities proposed by PG&E. Generally these parties took the position that PG&E should undertake more vigorous conservation activity. We will discuss generally PG&E's conservation activities in a following portion of this decision. We find that PG&E has justified its proposed test year conservation expense for the electric department.

Administrative and General Expenses

PG&E's estimate for total company test year administrative and general expenses is $104.6 million. The staff's estimate is $2.6 million less.

The staff estimates different levels of pension expense, as discussed in the preceding section of the opinion on gas department administrative and general expense. Based on the rationale discussed earlier, we will adopt as reasonable $1.6 million less expense than PG&E estimated, or $103.0 million.

Franchise Expense

We have adopted PG&E's revenue estimate and consistent with that we will adopt the franchise expense estimate. The staff and PG&E generally agree on the same franchise rate to be applied to gross revenues. At authorized rates we adopt the sum of $6,547,000.

Depreciation Expense

PG&E's estimate of test year depreciation expense is reasonable. No party challenged PG&E's depreciation expense estimate after PG&E adopted the staff's estimate.

Rate Base

PG&E adopted many of the staff's proposed adjustments to rate base, as well as the staff's estimate of weighted test year additions.

The difference between PG&E's and the staff's rate base estimate is $17.3 million, relating to the inclusion in rate base of cooling ponds at Pittsburg Power Plant Unit No. 7.

The staff believes PG&E was negligent in its constructing of cooling ponds for Pittsburg Unit No. 7 in that the ponds proved inadequate for the purpose intended, as PG&E subsequently built cooling towers to replace the cooling ponds. The cooling ponds were initially constructed because the San Francisco Bay Area Air Pollution Control District would not approve the usual cooling tower approach. Pittsburg Unit No. 7 was the first instance where PG&E used cooling ponds. After the cooling ponds were found inadequate, the Air Pollution Control District allowed the construction of cooling towers. Although there were obviously design problems[4] with the cooling ponds, we are of the opinion that at the time PG&E's conduct was generally prudent. PG&E had no alternative but to attempt the untried cooling method. We believe the staff's proposed adjustment relies too heavily on hindsight, and we will not adopt it.

## Combined Gas and Electric Revenue Requirements Issues

### Income Tax Expense

In this proceeding, as in the last PG&E rate case, there was considerable disagreement among the parties concerning methodologies which should be employed to estimate reasonable test year income tax expense. The Commission's Operations and Finance Divisions proposed different methodologies. TURN proposed that the Commission adopt the recommendations made by ALJ Coffey in his proposed report in Application No. 55509 et al., stating that the Commission's traditional method of computing ratemaking tax expenses is a "conglomeration of accounting fictions". We will discuss the positions of the parties. However, it is essential to this discussion to quote from Decision No. 89315, issued today in Applications Nos. 55509 and 55510, Phase II, wherein we address basically the same contentions and conflicting positions:

> "Arriving at an estimate of federal and state income tax expense for a future test year is one of the most complex and troublesome issues in ratemaking. A test year is an estimated results of operations, comprised of various ratemaking revenue, expense (including taxes) and rate base estimates, which is adopted by the Commission as a basis of determining prospective revenue requirement and the reasonableness of proposed rates. We anticipate the estimated test year components we adopt will reasonably approximate actual operating results. But given the multitude of variables in the real world of utility

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4/ The record indicates that PG&E in several instances provided the designer with erroneous design information. Ultimately, the designer and PG&E litigated in court for damages, suing each other, and the matter was settled without damages to either party.

operation, we recognize, as does anyone who observes the ratemaking process, that projected test year results can never exactly correlate with actual experience. The income tax component of the results of operation is particularly sensitive to many variables. For example, unusual expenses unanticipated when the operating expense (non-tax) component is established will mean less tax liability, because more expense deductions will be available to the utility. Likewise, higher than estimated revenues will mean a higher tax bill. And the situation gets more complex for energy utilities given the deferral of expense recovery for energy costs (Purchased Gas Adjustment and Energy Cost Adjustment balancing account expense recovery procedures). Interested parties have expressed the view that we should strictly allow for 'taxes as paid' when setting rates. Arriving at an adopted test year tax expense estimate that will reflect taxes 'as paid', or exactly correlate with actual expense during the prospective test year, is as difficult as estimating exactly the revenues to be realized by the utility.

"The ALJ's proposed report points out another complexity. In regulatory ratemaking the adopted income tax allowance depends on what types of expense deductions are or are not considered in arriving at the estimated income tax liability. Appendix B is a table (taken from the ALJ's proposed report) which illustrates the impact that such deductions can have on tax expense.

"The proposed report recommended that PG&E be ordered to reduce rates $56.5 million annually, and make refunds, on the basis that actual tax expense differed from the expense allowed in the Phase I decision. We are of the opinion that it would be unreasonable to adopt this recommendation, and we will discuss why. We appreciate the efforts of the interested parties who developed the record and made recommendations, which brings to our attention issues that should be fully explored and addressed. Ratemaking, to operate in the public interest, should be based on estimates that as accurately as possible reflect a reasonable allowance for income tax expense.

"If we were to adopt the recommendations put forth in the proposed report there could be a substantial effect on post tax interest coverage and the utility's earnings. We adopted a reasonable rate of return and return on equity for PG&E in the Phase I decision which recognized a certain interest coverage. Further, the rates authorized (based on our authorized rate of return) were determined by our traditional methodology of calculating and estimating income tax expense. To unilaterally change the method used to estimate income tax expenses without considering the effect on post tax interest coverage and return on equity (in a proceeding where authorized rate of return could, if warranted, be adjusted) would not be fair or in the best interests of maintaining financially sound utilities. Therefore, Phase II of these proceedings is simply not the forum where we can make drastic changes in calculating income tax expense. In fact, a general rate proceeding involving only one utility is not the best forum in which to obtain the most fully developed record on such proposed sweeping policy changes. For that reason, we are today issuing Order Instituting Investigation No. 24, joining all major utilities as respondents, to consider recommendations similar to those presented in the proposed report, and other recommendations on how we should estimate income tax expense for ratemaking. We expect full participation by our staff divisions, the respondent utilities, consumer interest groups, and the financial community on these important policy issues. Whatever we adopt as policy upon completion of the investigation will be implemented in appropriate proceedings affecting each utility's rates. This procedure is, we again stress, adopted so that we do not play blindman's buff, with possible adverse ramifications, on a less than adequate evidentiary record."

Having covered the general background on the complexity of ratemaking and income tax expense, and the reasons for the issuance of OII No. 24 today, we will briefly discuss the positions of the parties.

At the request of ALJ Gillanders, the company prepared Exhibit 97, which set out its income tax liability for the test year. Following the receipt of this exhibit, there was testimony and argument regarding which of three methods should be used by the Commission in arriving at a tax payment figure for test year 1978: the traditional ratemaking method; the method recommended by ALJ Coffey in his proposed report for Phase II of PG&E's last rate case; and the method proposed by the Finance Division. The Commission staff differed in its recommendations, with the Operations Division recommending the traditional ratemaking method and the Finance Division recommending a different test year tax expense determination.

Operations Division Position

The Operations Division submits that one of the crucial differences between its tax treatment and that proposed by the Finance Division is the treatment of the Diablo Canyon Nuclear Facility (Diablo). In its results of operations study for test year 1978, the Operations Division eliminated all aspects[5/] of Diablo on the premise that when it becomes operative (and can be included in rate base) there will be a special Commission proceeding (a "Diablo offset") to determine all of the expenses, fuel costs, effect on rate

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5/ In our Decision No. 86281, we proposed that all expenses of the applicant's Diablo Canyon Nuclear projects be excluded in the adopted test year and be considered in a separate proceeding. The Operations Division's staff results of operation in this proceeding has excluded all costs related to Diablo Canyon including interest deductions, ad valorem taxes both for book and as income tax deductions, and investment tax credit progress payments consistent with our prior Decision No. 86281. Because of the special circumstances involving Diablo Canyon, we will continue to abide by our policy as stated in Decision No. 86281.

base because of the operation of this new and expensive facility. Thus current property taxes on Diablo, as an example, have been excluded in estimating 1978 results of operations (including income tax expense). However, the Finance Division tax calculations include the income tax effect of these property taxes because they presumably will be paid by PG&E during the test year. The Commission's current procedure provides that all ad valorem taxes that have been and will be capitalized associated with the Diablo projects, will be recorded in the proper plant accounts when Diablo is operational at the <u>net</u> amount, reflecting income tax expense effects for both federal and state income taxes (which reduces the book value of the plant that goes into rate base). Furthermore, at the time of inclusion of Diablo Canyon in rate base, the proper treatment of all investment tax credits, including progress payments, will be considered.

Certain expenses totaling $3.5 million not considered necessary and reasonable to utility operations have been eliminated by the staff in its expense estimates. Once excluded from the cost of service method of setting rates, these expenses become discretionary to the utility. Should the company go forward and make such an expenditure, it will have an effect on tax expense (as a deduction) of approximately half the expended amount. The ratepayer is protected because these items are funded one-half by the stockholders and one-half by the effect of the tax rate. The Operations Division believes that eliminating these dollars from operating expenses and then including them in the tax calculation results in taking them away from the company twice, once by disallowing the expenses and again through the tax calculation.

The Operations Division further points out that interest expense relating to construction work in progress has not been included in its tax calculations because the interest element of the Allowance for Funds Used During Construction (AFUDC) itself reflects under the current method discounting the interest paid by the tax effect. If the calculation is made as suggested by the Finance Division, a gross calculation method would be used and the AFUDC and ultimately the book value of plant would actually be increased by excluding the discounting tax effect attributable to the interest portion of the AFUDC.

Although the Operations Division presented testimony and other examples to support its method, we do not believe it is necessary to extend this discussion.

Finance Division

The Finance Division recommends, as it did in Phase II of PG&E's Applications Nos. 55509 and 55510, that the Commission revise the method of estimating income taxes for ratemaking purposes to reflect as nearly as possible the company's actual tax liability for the test year.

The Finance Division generally proposes the following with respect to determining test year income tax expense:

1. That the Commission include property taxes paid on plant under construction as an expense tax deduction to compute test year income tax expense.
2. That the Commission cease the practice of not including as an expense deduction for determining income taxes various expenses that are disallowed by the Commission for ratemaking purposes.
3. That interest expense on construction work in progress, or AFUDC, be considered as test year expense for the purpose of calculating income tax liability.

Discussion

We believe that the above summation of the different proposed methodologies for calculating test year tax expense illustrates the complexity of this general issue. For example, the Operations Division approach (which we have traditionally applied) considers the tax expense of interest during construction and property taxes when plant (such as Diablo) is placed in service.

The plant cost is "netted out" or reduced to account for such tax effects. Accordingly, the ratepayer ultimately receives benefit of such tax deductions. Whereas, the Finance Division approach is to consider such tax effect in a particular test year. There is merit to both points of view, which is why we find it in the public interest to fully explore such issues in OII No. 24. In that forum we want and expect vigorous participation by all major utilities, various staff divisions, consumer interest groups, and the financial community. These important ratemaking policy issues deserve no less than such an extensive examination.

Accordingly, for purposes of this proceeding, we will apply our traditional methodology, as proposed by the Operations Division, to calculate estimated test year federal and state income tax expenses.

Also, consistent with our traditional methodology, we find it is reasonable for purposes of this proceeding, to apply the statutory federal and state tax rates for the tax expense components of the net-to-gross multiplier.

Adjustments Proposed by UC and GSA

UC and GSA proposed two adjustments, one to rate base and the other operating expense.

The UC-GSA witness recommends that $17.4 million or 10 percent of gas and electric department operating and maintenance expenses be disallowed until "Management surveys are designed, approved and conducted and the recommendations implemented" (Exhibit 56, p. 7). He based his recommendation on a PG&E sponsored study on PG&E's Pittsburg Unit No. 7 generating plant. The cross-examination of UC-GSA's witness shows that he relied on a very localized study and simple inductive analysis to conclude what may be wrong at one facility is wrong at all. We share the witness' concern about expense at Pittsburg Unit No. 7 (see our earlier discussion on electric production expense), but conclude his recommendation for a total company adjustment is not supported by evidence and we will not accept it.

UC-GSA's witness also recommended reducing PG&E's rate base by $14.3 million, the depreciated value of PG&E's Humboldt Bay Nuclear Power Plant, as well as associate expenses and working capital for the plant. His rationale is that the Humboldt plant is not operational and may not be operational in the foreseeable future. The staff and PG&E included the Humboldt plant in their test year rate base and expense estimates. The Federal Nuclear Regulatory Commission (NRC) is presently studying seismic conditions at the Humboldt site, and that agency will decide the future of the facility. We think it is premature to make an adjustment. If we adopted UC-GSA's recommendation, we would be prejudging the NRC. The Humboldt facility situation should be monitored closely, and in the next rate proceeding hopefully definitive information on its future, as far as the NRC is concerned, will be available.

Ad Valorem Taxes (Gas and Electric)

The only difference between PG&E and the staff for pre-adoption of Article XIII A of the California Constitution (Proposition 13) property tax expense is the result of the staff's proposed exclusion of cooling ponds at Pittsburg Unit No. 7 from rate base (electric). Since we did not adopt the staff's adjustment, we accordingly find PG&E's property tax estimate reasonable. The staff took no exception with PG&E's gas department estimate and we will adopt it.

The Effect of Article XIII A (Proposition 13)

The evidentiary record in these proceedings did not address the ramifications of recently adopted Article XIII A of the California Constitution. PG&E, in accordance with our suggestion in OII 19, has filed Advice Letter Nos. 1006-G and 687-E which proposes to reduce gas rates by $17.74 million and electric rates by $43.876 million. PG&E has also established a "tax initiative balancing account".

We are not going to change the estimate of ad valorem tax expense contained in the record, and we will not change the base rates authorized herein. However, we find that it is reasonable to require PG&E to make the rate reductions set forth in Advice Letter Nos. 1006-G and 687-E to go into effect concurrently with the increase in base rates authorized herein. In this manner we insure the return to California ratepayers of their share of Article XIII A actual tax savings realized by PG&E.

## Management Audit

In a previous section of this decision, under Electric Production Expenses, we have discussed the staff's studies and conclusions relative to the adjustment proposed for the Urich contract. We have taken the effort to describe in detail this adjustment, for we believe it illustrates the pressing need of monitoring the efficiency of the utilities we regulate. If we are to be more than a rubber stamp, translating cost increases into rate increases, we must scrutinize and exercise our investigatory ingenuity to insure utilities operate productively and efficiently. Our staff in this proceeding anticipated this need and has recommended that an operational and management audit of PG&E be made. We would like to make clear that, with the exception of PG&E's failing to audit the Urich costs, we have no preconceived notions on PG&E's efficiency and productivity. We believe, however, it is necessary that the company precisely examine its efficiency and demonstrate to us that it is attempting to improve its efficiency and reduce costs. A management and operational audit by an independent consultant may accomplish this result. Our staff should supervise this audit and we caution it to devise specific areas of inquiry that will maximize the benefits of such an audit, for we think a comprehensive management audit would very possibly be a waste of resources. When our staff has identified the areas of inquiry to be covered by a management and operational audit, it shall report its recommendations to the Commission for approval before the audit is contracted for and commenced.

## PG&E's Conservation Efforts

In earlier portions of this opinion we determined that PG&E's estimated test year conservation expense was reasonable, although $4.7 million of the rates authorized herein is subject to redirection in the event the insulation customer incentive programs are not approved on rehearing.

PG&E's plans for its 1978 energy conservation activities were presented in Exhibit 31. Table 1 of Exhibit 31 shows the following:

Summary of Estimated Conservation Activity Expenses for 1978

| | Estimated 1978 Expenses (000's) | | |
|---|---|---|---|
| Energy Conservation Programs | Base | Supplemental | Total |
| Insulation | $ 947 | $ 6,133 | $ 7,080 |
| Appliances and Devices | 1,534 | 1,893 | 3,427 |
| Homes | 562 | 515 | 1,077 |
| Commercial-Industrial-Agricultural | 2,016 | 2,555 | 4,571 |
| Solar | 645* | 964 | 1,609 |
| General | 1,735 | 2,069 | 3,804 |
| Subtotal - Programs | $ 7,439 | $14,129 | $21,568 |
| Other Conservation Activities | | | |
| Load Management | $ 668 | $ 7,279 | $ 7,947 |
| Research and Development | 455 | 0 | 455 |
| PG&E General Office Departments | 2,784 | ** | 2,784 |
| Subtotal - Other | $ 3,907 | $ 7,279 | $11,186 |
| Total Conservation Expenses | $11,346 | $21,408 | $32,754 |

*Includes solar R&D.

**Included in individual programs.

PG&E expects that its energy conservation programs will save customers about 2.434 billion kwh and 946 million therms on a life-cycle basis.

## The Staff's Position

The staff, during these proceedings, ultimately accepted as reasonable PG&E's test year budget for conservation.

The staff witness' analysis indicates that PG&E's Exhibit 31 conservation programs are cost-effective. However, the staff recommends the following modifications to achieve additional cost-effective conservation. The utility should develop an effective program to insulate residential rental property and commercial buildings. The appliances and devices programs should be expanded to include wholesalers, contractors, and commercial and agricultural sales. The customer incentive programs should be expanded to include public buildings other than schools. Solar involvement should be limited to domestic water heating guarantee arrangements, and distribution of tax, product quality, and financing information. PG&E should publish and distribute information on the availability, use, and guarantees of solar equipment. PG&E should develop a program to dispose of energy inefficient appliances in conjunction with any program to encourage sales of energy efficient appliances. The devices program to sell water heater blankets should be changed to provide blankets and shower heads for a $25 maximum installed per customer utility cost to customers with R-19 attic insulation pursuant to Decision No. 88551. The staff recommends $4,750,000 of the conservation budget be used for this program; $850,000 of this amount should be reallocated from the $964,000 requested for supplemental solar programs. The homes point system should be revised to exclude optional home appliances. Publicity for CIA awards should be limited to trade media, and expenses for banquets should not be charged to ratepayers. CIA awareness efforts should be increased. PG&E should increase the use of direct customer contact in lieu of advertising to provide customer information on conservation. PG&E should explain in detail in its March 31, 1979 conservation report the benefits it receives from Electric Power Research Institute and American Gas Association research projects. PG&E should work to develop market research methods that accurately measure conservation savings. PG&E should have between 80 and 86 full-time commercial and industrial auditors by the end of 1978. PG&E should provide a bill insert describing relative energy efficiency of different refrigerator and freezer models. PG&E should amend Rule No. 14.1, Prohibition and Curtailment Provisions, to restrict the use of pool pumps and filters to off-peak periods. The staff recommends that the Exhibit 31 programs be ordered with these modifications.

The staff also recommends that $7,279,000 be approved for load management expenses. Because of the experimental nature of the programs and the large sum of money involved, the staff recommends that PG&E be ordered to report in its forthcoming annual December conservation report the results of its load management experiments, including any benefits such as decisions to forego new plant construction.

The staff believes PG&E's energy savings goals, efforts, and accomplishments are inadequate. PG&E's actual and projected energy savings are, according to the staff, minimal. It projects 1.31 percent electric and 2.39 percent gas savings in test year 1978 due to residual benefits from 1976 and 1977 and new 1978 programs. Savings will be 4.4 percent of electric and 7.8 percent of firm gas sales by 1987. The staff submits that these are savings partially attributable to PG&E's Conservation and Services Department setting overly modest goals. For example, the actual and projected savings for electric use for 1976, 1977, and 1978 are .42 percent, .38 percent, and .65 percent, respectively; the gas savings are .35 percent, .88 percent, and 1.06 percent. The modesty of these actual and projected savings becomes apparent when one compares them with the 10 to 20 percent indicated potential savings for the commercial and industrial sector. On a per customer basis, PG&E's conservation expenditures are lowest of the three major gas and electric utilities. One method the staff used to measure the effectiveness of the utility's conservation efforts is a yes and no checklist of energy conservation activities.

PG&E's performance was unsatisfactory in the five most important areas on the list: CI audits, residential rental property insulation, provision of information on energy efficient appliances to customers, cogeneration, and load management. As noted above, PG&E's projected savings for CI audits are far below potential savings for commercial and industrial customers. Nonetheless, conservation attributable to CI audits has been limited because of a lack of personnel and the utility's lack of interest in expanding the audit program. PG&E failed to develop an effective residential rental property insulation program. The checklist in Applications Nos. 55509 and 55510 also indicated a failure to develop an effective residential rental property insulation program.

According to the staff, PG&E has not established goals for using existing cogeneration potential. A staff witness testified that this failure was especially crucial in the evaluation of PG&E's conservation programs. Cogeneration is important because it can reduce the utilities' load obligation, thereby reducing its need to construct new generating capacity and its use of fossil fuels. None of the cogeneration projects reported under consideration in Applications Nos. 55509 and 55510 has come on line, and the reported potential under consideration in this application has declined in the interim between the two rate cases.

The staff believes PG&E has not identified its customers' nonessential uses for load management purposes or established long-term load management goals by class. If PG&E were aware of customers' nonessential uses then it could manage its load by requesting customers to reduce or shift consumption for these uses.

The staff thinks that perhaps one reason for PG&E's performances is its apparent dependence on the Commission and its staff to determine how it should cost-effectively spend conservation dollars. Counsel for PG&E extensively questioned Commission witnesses as to whether they had ascertained reasonable methods to encourage residential rental insulation, floor insulation, storm windows, cogeneration, disposal of inefficient appliances, compile data on energy inefficient appliances, and so forth. According to the staff, it is PG&E's obligation to determine through discussion with the staff and its own studies, prior to hearings on the evaluation of its conservation efforts, which conservation programs are cost-effective and worthwhile.

The staff's critique of PG&E's 1977 conservation efforts, as summarized above, basically goes to the failure of PG&E to implement on an extensive basis its supplemental conservation programs in 1977.

According to the staff, the Commission has put PG&E on notice that it will consider the vigor, imagination, and effectiveness of its conservation activities in arriving at an appropriate rate of return. The staff submits that PG&E's vigor, imagination, and effectiveness are inadequate. Therefore, in addition to the above-outlined recommendations, the staff's Energy Conservation Team recommends a .05 percent rate of return reduction. In addition, the Legal Division recommends that an OII be issued to investigate the establishment of conservation goals, and their impact on PG&E's construction plans. (This is accomplished by our issuance today of OII No. 26.)

The staff's recommended rate of return reduction is .05 percent or $5.8 million of gross revenues. The rate of return recommendation was designed by the staff to stimulate PG&E's conservation efforts without depriving it of necessary revenues.

<u>The Energy Commission's Analysis</u>

The Energy Resources Conservation and Development Commission (Energy Commission) participated extensively and filed briefs. It submitted constructive recommendations to improve the effectiveness of PG&E's programs, and concluded that we should question the vigor and imagination of PG&E's conservation efforts. No recommendation on a rate of return adjustment for inadequate conservation measures was submitted by the Energy Commission, stating in its opening brief:

> "The CEC will not attempt to make any recommendations with respect to a specific rate of return, particularly given the absence of any guidance from previous PUC decisions in defining the precise mechanism for adjusting the rate of return according to the three conservation criteria of vigor, imagination, and effectiveness. We believe that in the absence of guidelines or standards for a utility to meet in demonstrating the vigor, effectiveness, and imagination of its conservation programs, it is impossible for either interested parties or the PUC to assess the inadequacy of utility conservation programs. We furthermore believe that the lack of such guidelines inhibits effective regulation of utility conservation efforts. We, therefore, urge the Commission to explicitly define and explain criteria for determining the vigor, effectiveness, and imagination of conservation programs and the method for applying these criteria to rate of return adjustment decisions."

The Energy Commission's evaluation of PG&E's programs, and its proposed recommendations, are as follows:

1. Insulation Programs. PG&E is criticized for not studying the extent to which the insulation program could be expanded, and for not developing specific information on the cost-effectiveness of attic insulation. If PG&E developed better information on cost-effectiveness, customers may be more likely to insulate and the insulation program could be realistically evaluated. The Energy Commission urges that a program be developed to make landlords retrofit insulation.

2. Appliances and Devices. The Energy Commission questions PG&E's incentive program to induce sales of pilotless gas ranges because the Energy Commission has adopted regulations mandating such ranges as of July, 1978. Also, the incentive program to encourage retrofitting conventional light fixtures to fluorescent was questioned, and it was suggested that funds could be better used for hiring additional energy auditors.

3. Commercial-Industrial Audits. The Energy Commission believes energy audits are "outstanding" as a cost-effective conservation activity. It proposes accelerating the program.

4. Swimming Pool Time Clock Program. It is recommended that PG&E's program should be specifically ordered by the Commission because it holds great conservation promise.

The Energy Commission concludes in its opening brief that:

> "It is impossible to determine at this time, however, whether or not PG&E's claimed savings are true and, even more importantly, whether or not such savings indicate an effective conservation program. For example, factors other than conservation may slow demand in an area, and conversely, there may be significant conservation savings even with increased demand. Yet PG&E's current conservation measurement techniques, such as its estimate that it is responsible for 75% of insulation sales in its service area because a similar percentage of people recall its advertising, are inadequate in making a proper assessment of effectiveness. A far more accurate and sophisticated evaluation and monitoring system, that goes beyond merely estimating savings, is needed. Such a system would include assessment of what actions actually occurred and what was the actual effect on those actions on energy consumption.
>
> "Careful examination is also needed, on an individual customer level, of other factors influencing usage to ensure the effect of such factors are not mistaken for conservation. Finally, there must be thorough integration of achieved and estimated results with PG&E's demand forecast and supply planning. This integration is necessary if conservation is to actually replace currently planned new facilities and supplies, as the PUC has declared it should."

Position of the Environmental Defense Fund (EDF)

The EDF participated extensively, and presented numerous meritorious suggestions and observations. We are impressed by witness Willey's testimony. Today we are issuing OII No. 26 to fully explore PG&E's resource planning, both short- and long-term for as EDF points out:

> "The Commission's recent experience with SDG&E and Sundesert shows the importance of timely review, by it, of at least the major elements of a utility's long-range supply plan. It also highlights the importance of undertaking such review in comprehensive fashion, not merely plant by plant as each one is proposed." (EDF opening brief, p. 13.)

In addition to OII No. 26, we are ordering PG&E to commence immediately studies on, among other things, generating facility repowering. We would not be discharging our duty to the ratepaying public if we failed to actively oversee the reasonableness of proposed utility resource plans.

EDF believes PG&E has set its conservation goals too low and understates the potential for conservation. It is EDF's recommendation that PG&E's rate of return be reduced resulting in a gross revenue reduction of $79.8 million.

Position of TURN

TURN believes PG&E's conservation efforts have been and are less than mandated by the Commission. It states that the staff has not fully investigated the test year conservation budget to determine the reasonableness of PG&E's estimate. In particular, TURN questions whether PG&E's management should have the discretion of devising and implementing conservation programs because TURN believes it is an inherent conflict of interest for an energy utility to promote conservation.[6/] Another TURN position is that local governmental entities should undertake conservation programs, and that increasing PG&E's rates to fund the utility's conservation efforts results in a drain on financial resources that could otherwise be raised for local conservation programs.

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6/ To mitigate this result we adopted SAM (see the earlier discussion on gas revenues) and are issuing an OII into whether and how to establish a similar SAM for electric utilities.

City of Palo Alto and Southwest Gas

Palo Alto and Southwest request that PG&E's expense for conservation programs not be passed on to them (and ultimately their customers), and that rates be accordingly reduced. In essence, both Palo Alto and Southwest contend that they have their own on-going conservation programs; that PG&E's conservation activities have little direct impact on their customers; and that an undue burden would be placed on their own customers if those customers must bear a portion of PG&E's conservation expenses in addition to those of their own supplying utility. We cannot grant this request.

First, as extensively discussed in Decision No. 89315, issued today in Application No. 55510 (Phase II), the resale rate is not based on a compilation of incremental costs from which one identifiable expense (such as conservation promotion) can logically be deducted.

Second, Palo Alto and Southwest, as all gas users, benefit from PG&E's conservation efforts. California's gas supply must be conserved and made to continue as long as possible to avoid severe economic hardship on the State. It is in the public interest for all who distribute gas, public and municipal utilities alike, to take steps to conserve.

If we adopted the policy suggested by Palo Alto, it could lead to a multitude of resale customers or local jurisdictions claiming that in view of their respective conservation efforts they should not contribute to PG&E's conservation programs. Such a policy would be short-sighted. Entities should not quibble over bearing the obligation to encourage conservation. They collectively benefit from the efforts of each in that there will be gas available for a longer period if conservation is promoted. Palo Alto's request, based on the foregoing, is not reasonable or in the public interest.

Position of UC

The principal fault UC finds with PG&E is in the area of cogeneration. It thinks PG&E's policies discourage developing cogeneration generating potential, based on its attempts to develop a cogeneration project at its Davis Campus. The conclusions were that PG&E's Schedule No. S-1 standby tariff is unnecessary and should be eliminated and that the Commission should establish tariffs requiring PG&E to purchase energy and capacity for a cogenerator at the same rate PG&E would sell energy and capacity to that cogenerator.

Discussion

It is apparent that many parties find fault with PG&E's conservation efforts. Our reservations are also discussed in the rate of return section of this opinion. There are areas where PG&E's management is not aggressively taking the steps it should, and in addition to issuing OII No. 26 today, we will order studies to begin immediately into the following:

1. Repowering existing generating facilities, both steam plants and hydroelectric units.
2. Expanding existing facilities and facility maintenance and modification as an alternative to new facilities.
3. Sources of auxiliary and cogenerated power which can be used during high demand periods.

Despite some apparent shortcomings in PG&E's conservation effort we are of the opinion that we should not reduce its authorized rate of return. We discussed earlier, however, that if PG&E had been more imaginative in exploring resource options we would be inclined to authorize a higher return on equity.

PG&E generally contends that the staff's criticisms are the result of not being familiar with PG&E's actual conservation effort. The defense of PG&E in opposing the staff's recommended rate of return adjustment is stated in its opening brief (p. 153):

> "PGandE does not claim that all of this reduction in gas and electricity consumption is due to its conservation efforts alone; there are numerous other economic and social factors impacting gas and electricity consumption patterns. However, PGandE does have an active and extensive conservation program and the ultimate goal that this Commission is seeking to attain, a reduction in consumption, is occurring. To assert that PGandE, and thus its top management, are not pursuing conservation diligently when sales are defying historic patterns is unreasonable.
>
> "Fourth, what the Staff describes as a lack of top management diligence in promoting conservation is, in fact, the reasonable and prudent response of top management to hesitant, ill-defined, and inconsistent Commission conservation policies."

PG&E states that EDF's recommendations, as they pertain to adjusting allowed expenses and rate base as a means of imputing a long-range resource plan, is "destructive to the concept of test year ratemaking". Although, as indicated previously, we are impressed by EDF's presentation, we are not convinced that it is reasonable to adopt a specific revenue requirement adjustment as proposed by EDF at this time. In order to not delay PG&E's next general rate proceeding and allow a forum for the staff, EDF, and PG&E to fully explore resource planning, it is appropriate to issue OII No. 26. We expect timely responses by PG&E to the data requests of the staff and interested parties in that OII, for the issues to be addressed are critical and we must explore them as rapidly as possible. The policy conclusions we reach as a result of OII No. 26, in which EDF may and should participate, will be implemented. And in subsequent rate proceedings we can insure prudent resource policies are followed; if they are not, we can impute the operating efficiency as suggested by EDF in adopting a reasonable test year results of operations.

We believe some of the parties forget that conservation, undertaken on a massive scale, is a relatively new science. Much progress has been made, and many more innovations and ideas will emerge as utilities, consumers and regulators head, as they must, toward a conservation-oriented energy policy. It is well settled in our minds that continued growth of new generating capacity is too financially and environmentally expensive for Californians. The many recommendations of the parties, and just the issues they raised, is, in our opinion, an excellent education for PG&E. The utility's management should carefully review the material and testimony on conservation submitted in these proceedings, for it is apparent PG&E does not have a monopoly on answers or talent in the conservation field.

We will continue our review of PG&E's conservation activity in the next general rate proceeding. If we conclude that management is recalcitrant or lazy in implementing conservation programs and prudent resource plans, we will <u>not</u> be hesitant to adjust rate of return more drastically than proposed by the staff in these proceedings.

We do not, however, feel that this should be the only means by which we should encourage conservation efforts. At the onset of the energy crisis, the Commission was not staffed to effectively direct ~~special~~ specific utility conservation programs, thus primary reliance was placed upon the resources of utility personnel and management. Now that we have reorganized and manned our staff to effectively address conservation issues, we will undertake a much more active role in establishing and directing, as well as monitoring, specific utility conservation programs. Such Commission leadership exercised in conjunction with appropriate rate of return adjustments should prove more effective in achieving energy conservation than the rate of return sanction alone.

We would like to reiterate that our insistence on an overall conservation ethic and approach on the part of the energy utilities we regulate will <u>not</u> be detrimental to the shareholder. If the measurement of earnings we apply is return on common equity the utility is not penalized for slowing generating plant expansion. Likewise, we have adopted an SAM for gas utilities to insure that declining sales do not erode earnings, and for electric utilities we will shortly begin an investigation into the establishment of an ECAM.

PG&E has not complied with the intent of Decision No. 84902 where we stated: "We expect utilities to explore all feasible cost-effective means of conservation, including...providing customers with detailed intelligible information on appliance energy use by brand name ('Shoppers Guide')..." PG&E has distributed the "Shoppers Guide" only to appliance dealers and customers specifically requesting it. We will direct PG&E to distribute the "Shoppers Guide" to all customers every 18 months until further order.

Gas Rate Design

Gas Rate Design Proposals[7/]

PG&E

PG&E's rate proposal suggested consolidation of density rate zones, increases to lifeline and nonlifeline rates, and elimination of the demand charge component in a new uniform resale rate.

No proposal was made to introduce a multi-tier residential rate structure, but the possibility of a one-zone inverted multi-tier rate structure was recognized. Thus, PG&E stated its residential increases in terms of simple uniform increases for lifeline and nonlifeline usages ($0.0148 and $0.0171 per therm, respectively) so that these increases could be applied to any pattern of single-zone inverted rates adopted by the Commission. After the proposal was filed but before hearings began, the Commission did in fact eliminate density zones and adopt 3- and 5-tier inverted residential rate schedules (Decision No. 87585). The PG&E proposed increases can thus be applied to the existing 3- and 5-tier, one-zone structure which now exists for residential rates.

7/ In order to have the most complete and current evidentiary record on gas rate design issues, we are incorporating into this proceeding the record in Application No. 57978, PG&E (purchased gas offset proceeding).

In the nonresidential category for P-1 and P-2 usage PG&E also anticipated the zone consolidation and proposed a single increase of $0.01921 per therm plus an increase in the customer charge of $1.63 per month. These increases are slightly lower than those indicated in Exhibit 11, where a clerical error appears, but are the increases upon which the proposed revenue increase is based. These increases can also be added to existing rates, but PG&E does not support inverted rates for this class of customers.

The proposed increase is identical at $0.01760 per therm for commercial and industrial customers in the P-3 and P-4 groups and for the P-5 steam-electric category. As originally stated, this proposed change would have increased rates to $0.23243 per therm, but considering intervening offset changes on July 1 and July 12, 1977, the increase would raise these charges to $0.2466 per therm.

In the resale category, uniform rates are proposed for the lifeline and nonlifeline portions of sales to the four resale customers. A uniform increase of $0.02582 per therm would be assessed for the lifeline portion of each customer's deliveries and an increase of $0.00929 per therm for the nonlifeline portion of these sales over the present weighted average lifeline and nonlifeline rates, respectively.

Commission Staff

The staff recommended rate spread at 100 percent of the requested increase averages 8.1 percent (Exhibit 69). Average increases by priority are: P-1 residential - 7.8 percent; P-1 and 2, commercial and industrial - 8.3 percent; P-3, 4, and 5 - 8.2 percent; and resale - 8.1 percent.

Staff recommendations for residential customers include a $1.30 customer charge and five tiers at the following per therm rates: TIR-.1523, TIIR-.2009, TIIIR-.2132, TIVR-.2255, and TVR-.2377.

The staff proposal includes a three-tier nonresidential P-1 and P-2 rate structure at the following per therm rate: TIC-.2255, TIIC-.2377, and TIIIC-.2431. The purpose of the tiered design is to encourage conservation. The recommended P-3, 4, and 5 per therm rate is .2477; the resale lifeline and nonlifeline rates are .1523 and .2051, respectively. Significant changes for resale customers include modification for lifeline allowances based on current usage and elimination of the demand charge.

In addition, the staff was asked by the hearing officer to give its recommendation on special rate consideration for residential gas air conditioners.

According to the staff (Exhibit 91), "The existing rate structure is reasonable for gas air conditioning use and no special allowances are necessary."

California Manufacturers Association (CMA)

CMA believes that the manner in which the very large rate increases of the last several years have been spread has resulted in a system rate design that is out of balance. While this Commission's actions during this period have responded to changing conditions and concerns, chief among them the lifeline legislation and a rapidly diminishing gas supply, those actions, according to CMA, seem to have been taken hurriedly and without full consideration of their effect on customers and the utility. According to CMA, the rates paid by industrial customers have skyrocketed, only in part due to the increased costs experienced by PG&E. As a result of the rate design policy adopted by the Commission, CMA believes numerous problems have been created for customers and the utility.

CMA believes that the present rate design deceives large numbers of residential customers into believing that gas is an inexpensive commodity and that the installation of facilities necessary to provide service costs virtually nothing, while at the same time working to discourage uses of gas by other customers which are both efficient and useful. It believes that the existing rate design is so out of balance that it is not practical to correct the problem fully in this proceeding. But, as it also believes that the Commission should make a significant move in that direction in this proceeding, it recommended the following rate design:

Transitional CMA Rate Proposal

| | Present | Future |
|---|---|---|
| **Residential** | | |
| Customer Charge | $1.20/Mo. | $2.50/Mo. |
| Lifeline Commodity Charge | $0.1417/Th. | $0.175/Th. |
| Tier 2 Commodity Charge | $0.200/Th. | $0.2353/Th. |
| Tier 3 Commodity Charge | $0.219/Th. | $0.3006/Th. |
| **Priorities 1 and 2** | | |
| Customer Charge | $1.20/Mo. | $6.90/Mo. |
| Commodity Charge | $0.219/Th. | $0.213/Th. |
| **Priorities 3 and 4** | | |
| Commodity Charge | $0.229/Th. | $0.229/Th. |
| **Priority 5** | | |
| Commodity Charge | $0.229/Th. | $0.229/Th. |
| **Resale** | | |
| Commodity Charge | $0.1735/Th. | $0.1735/Th. |

Kerr-McGee Chemical Corporation (Kerr-McGee)

Kerr-McGee proposed two separate and alternative methods of spreading the revenue increases sought by PG&E. The first rate proposal was called the "Equalized Markup" or "EMU" proposal and the second was called a "Conservation Incentive Rate Design" or "CI" design. The EMU rate design starts with costs incurred by PG&E to serve the various customer classes and involves other ratemaking factors in spreading in an equitable and conservation promoting fashion, the burden which has been imposed upon nonlifeline customers in order to subsidize below-cost service to lifeline users. The CI proposal is principally intended to promote the Commission's objective of energy conservation rates and improve stability of earnings.

Kerr-McGee selected a specific rate design that in its opinion should be adopted by the Commission. The recommended CI rate design is characterized by the following parameters: (1) a $2.40 per month residential customer charge; (2) the lifeline commodity rate of 15.68 cents per therm proposed by PG&E; (3) a uniform commodity charge equal to the application rate for interruptible gas usage of 21.48 cents per therm; (4) a uniform nonresidential general service customer charge of $12.97 per month; and (5) a CI charge of $.44378 per factor month.

The rate design proposals of CMA and Kerr-McGee place emphasis on increasing fixed customer charges. We have repeatedly found that it is reasonable to price gas by units of use as a means of encouraging conservation. If we adopted high fixed customer charges, the units of gas consumed could not be priced to result in the greatest savings to the customer for conserving units of gas use. Accordingly, we find that CMA's and Kerr-McGee's proposals are not reasonable and in the public interest.

Southwest Gas Corporation (Southwest)

Southwest recommends and urges adoption by the Commission of a commodity-type rate or two-part commodity-type rate or single commodity-type rate, with the elimination of the demand component of the two-part PG&E rate that is listed in Schedule No. G-63.

City of Palo Alto (Palo Alto)

It is Palo Alto's position that its Municipal Utility be exempt from gas rate increases due to PG&E's conservation program expenses for the following reasons:

1. PG&E's conservation programs do not directly benefit the Palo Alto Gas Utility as a resale customer.
2. PG&E's conservation programs do not directly benefit the customers of the Palo Alto Gas Utility.
3. Palo Alto should be given credit for its own conservation programs.
4. The imposition of a rate increase to cover PG&E's conservation programs would impose an inequitable burden upon Palo Alto's customers.

Regarding the proposal by the staff and PG&E to institute uniform commodity rates for all resale customers, it is Palo Alto's position that uniform rates have been proposed for simplicity and administrative convenience. However, an important matter must be brought to the attention of this Commission. Applying uniform rates to resale customers will deny Palo Alto a gas rate decrease recently granted, and reinstate a previous offset increase to Palo Alto which this Commission has ordered to be modified (Decision No. 88310). Since PG&E and staff published their proposed uniform resale commodity rates, an appropriate rate reduction has recently been granted Palo Alto. On January 10, 1978, Decision No. 88310 was rendered reducing Palo Alto's commodity rate $.0032 per therm for nonlifeline usage. This decision corrected an unintended large increase to Palo Alto's G-60 rate schedule from previous offset Decision No. 87585 and did not affect the other resale schedules.

If uniform rates are implemented to all resale customers, Palo Alto will certainly lose this recent rate decrease. In so doing, the unintended large increase that was applied to the G-60 rate schedule as a result of Decision No. 87585 will be reinstated, and Palo Alto will be burdened with an increase in gas purchases of approximately $83,000 per year. It is Palo Alto's position that this rate reduction of $.0032 per therm for nonlifeline usage be reflected in the arrived at G-60 commodity rate. To ignore this rate reduction would be improper and mathematically incorrect.

Regarding uniform commodity rates for resale customers, it is Palo Alto's position that uniform rates are inequitable for a broader reason; all resale customers are not alike. Indicative of this diversity is the four different resale lifeline percentages. Staff and PG&E did not recommend a uniform lifeline percentage for all resale customers.

We have already addressed Palo Alto's request for a rate adjustment as a result of its conservation efforts in the preceding portion of this opinion on PG&E's conservation activity. As for the remaining resale rate issue, we today issued Decision No. 89315, in Application No. 55509 (Phase II), which directs that Palo Alto's resale rate be established in this proceeding to provide a 20 percent differential between gross revenues and purchased gas expense which is equivalent to $0.0458/therm of Palo Alto's purchases (using PG&E's general service rates as a basis of establishing this differential). That issue was extensively addressed in that proceeding, and essentially the same arguments were presented then as in this proceeding. We find that PG&E's resale rate to Palo Alto should be established to allow Palo Alto the $0.0458/therm differential over purchased gas cost pursuant to Decision No. 89315, in Application No. 55509.

Adopted Gas Rate Design

The combined revenue increases from Application No. 57285 and Phase I of Application No. 57978 will produce an overall increase in excess of 12 percent. This is a substantial increase that requires careful placement in order to satisfy our ongoing concerns for a healthy industrial and living environment while continuing to encourage conservation.

In our previous Decision No. 87585, the rates to the lowest priority industrial customers were set so as to provide a planning signal for the equating of natural gas with alternative fuels or with the incremental cost of new (and incrementally the most expensive) natural gas supplies. PG&E has testified that some of its large industrial P-3 and P-4 customers have discontinued gas service and have converted to alternative fuels, particularly when oil prices fluctuate downward.

The erosion of sales to these two classes of customers prompted PG&E to develop and propose Schedule No. G-52 in Application No. 57978 (the record of which is incorporated into these proceedings). The two salient features of the Schedule No. G-52 rates were its applicability based on the type of alternative fuel that the customer was capable of using[8] and the proposed reduction from the present 22.90 cents per therm to a flat 20.00 cents per therm. Although PG&E did present evidence to support its proposed Schedule No. G-52 rate, the objections raised concerning potential price fluctuations of the alternative fuel market, the distinctions between P-3 and P-4 customer characteristics, the staleness of the information used and the general naivete of the study suggest that more work needs to be done before substantial weight can be given to the proposed rate.

On the other hand, the undisputed departure of certain customers from PG&E's system is indicative that the gas price adopted in Decision No. 87585 represents a plateau from which to survey the alternative fuel market. We will therefore authorize a Schedule No. G-52 rate as proposed by PG&E, but we find that a rate of 22.90 cents per therm is reasonable. This will provide a point of stability in our alternative fuel pricing policy. As more information is developed by the staff, PG&E, and other interested parties, further opportunities for differentiation along the lines of alternative fuel use may present themselves. For the future, PG&E's semiannual Gas Cost Adjustment Clause (GCAC) and SAM filings should be used to develop and maintain rates that are current and competitive with respect to alternative fuels and new gas supplies.

The remainder of the customers in P-3 and P-4 classes, while capable of using alternative fuels, has selected alternative fuels that are generally accorded a higher price in the market place. Some increase to these customers is therefore justified and reasonable if their alternate fuel cost is taken into account. For this reason, the Schedule No. G-50 rate will be increased by 10 percent from 22.90 cents per therm to 25.20 cents per therm.

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8/ "APPLICABILITY

"Applicable to natural gas service to uses classified in Rule No. 21 as P3 and P4, for which the alternate fuel is exclusively oil with a viscosity higher than 150 Saybolt Seconds Universal (SSU) at 100°F (commonly referred to as Grade No. 5 and Grade No. 6 fuel oil)."

The next substantial issue relates to the question of lifeline rates. PG&E has indicated that systemwide average gas rates have increased more than the statutory 25 percent of rates in effect on January 1, 1976. We believe it is reasonable and appropriate to allocate a portion of the revenue requirement increase to lifeline usage. Considering that the average increase under these applications is in excess of 12 percent and that lifeline customers have not, until now, received any increases, a rate increase of 16.6 percent (from 14.17 cents per therm to 16.52 cents per therm) will apportion a reasonable share of this increase to the first usage block, or lifeline quantity.

The rates to nonresidential P-1 and P-2 customers will also be increased by 16.6 percent. This will reasonably maintain the rate relationship between residential lifeline usage and other high priority customers who do not have alternative fuel capability. ✓

Residential rates for quantities in excess of lifeline usage will be increased substantially and in a manner to promote conservation. The rate increases will provide a steeper gradient than the present inverted rates, and thereby further encourage residential customers to conserve use of natural gas and to adopt alternative and renewable energy sources such as solar. This course of action was recommended by Alten Corporation to improve the economics of solar conversions and prevent waste of natural gas; that effect, in the context of a sound, long-range energy policy for California, is most ✓ desirable.

In order to focus the economic effect of our rate changes on summer use, the 5-tier residential rate should be modified. The winter Tier IV will be lowered to Tier II and the excess winter usage will be charged at the Tier IV rate instead of the Tier V rate. The blocking and applicable volumes are shown on the following Table G-1:

TABLE G-1

PACIFIC GAS AND ELECTRIC COMPANY
REVISED RESIDENTIAL TIERS

| | | Blocking (Therms) | | | |
|---|---|---|---|---|---|
| | | Winter | | | |
| Tier | Summer | W | X | Y | Z |
| **Current** | | | | | |
| I | 26 | 81 | 106 | 141 | 166 |
| II | 26 | - | - | - | - |
| III | 26 | - | - | - | - |
| IV | 26 | 81 | 106 | 141 | 166 |
| V | +104 | +162 | +212 | +282 | +332 |
| **Revised** | | | | | |
| I | 26 | 81 | 106 | 141 | 166 |
| II | 26 | 81 | 106 | 141 | 166 |
| III | 26 | - | - | - | - |
| IV | 26 | +162 | +212 | +282 | +332 |
| V | +104 | - | - | - | - |

Volumes (MMTH)

| | Current | | | Revised | | |
|---|---|---|---|---|---|---|
| Tier | Summer | Winter | Total | Summer | Winter | Total |
| I | - | - | 1,619.8 | - | - | 1,619.8 |
| II | 234.8 | 0 | 234.8 | 234.8 | 320.8 | 555.6 |
| III | 96.3 | 0 | 96.3 | 96.3 | 0 | 96.3 |
| IV | 37.3 | 320.8 | 358.1 | 37.3 | 136.5 | 173.8 |
| V | 118.7 | 136.5 | 255.2 | 70.5 | 0 | 118.7 |

The foregoing rate design changes and associated sales volumes and revenues are shown in the following Table G-2. The disposition between the increases attributable to Application No. 57285 and to Phase I of Application No. 57978 are shown in Table G-3.

A bill comparison is shown in Table G-4 for the changes in residential rates. This illustrates the magnitude of the increases that the individual customer will experience at various consumption levels.

TABLE G-2

Gas Department Rates

Year 1978 Estimated

| Category | Volume MM Therms | | Present Rates (7-12-77) | | Authorized | | | |
|---|---|---|---|---|---|---|---|---|
| | | | $/Therm | MM$ | Rate $/Therm | Revenue MM$ | Increase 2/ MM$ | Increase 2/ % Rate |
| | Present | Adopted | | | | | | |
| Customer Months | 31.6 | | 1.20 | 37.9 | 1.20 | 37.9 | --- | ---- |
| Priority 1 (Residential) 1/ | | | | | | | | |
| Tier I (Lifeline) | 1619.8 | 1619.8 | .1417 | 229.5 | .1652 | 267.6 | 38.1 | 16.6 |
| Tier II | 234.8 | 555.6 | .1804 | 42.4 | .2500 | 138.9 | 96.5 | 38.6 |
| Tier III | 96.3 | 96.3 | .1896 | 18.3 | .2750 | 26.5 | 8.2 | 45.0 |
| Tier IV | 358.1 | 173.8 | .2160 | 77.3 | .3000 | 52.1 | (25.2) | 38.9 |
| Tier V | 255.2 | 70.5 | .2190 | 55.9 | .3760 | 26.5 | (29.4) | 71.7 |
| G-1 N (Non-Lifeline) | --- | 48.2 | .2190 | --- | .2750 | 13.3 | 13.3 | 25.6 |
| Total Residential | 2564.2 | 2564.2 | .1651 | 423.4 | .2047 | 524.9 | 101.5 | 24.0 |
| Non-Residential | | | | | | | | |
| Priority 1 & 2 (G-2) | 1852.1 | | .2190 | 405.6 | .2554 | 473.0 | 67.4 | 16.6 |
| Priority 3 & 4 (G-50) | 882.3 | | .2290 | 202.0 | .2520 | 222.3 | 20.3 | 10.0 |
| Priority 3 & 4 (G-52)(new schedule) | 360.0 | | .2290 | 82.4 | .2290 | 82.4 | | |
| Priority 5 (G-57) | 87.0 | | .2290 | 19.9 | .2290 | 19.9 | | |
| Priority 5 (G-55) | 1665.2 | | .2290 | 381.3 | .2290 | 381.3 | | |
| Total Non-Residential | 4846.6 | | .2251 | 1091.2 | .2432 | 1178.9 | 87.7 | 8.0 |
| Resale # | | | | | | | | |
| Lifeline | 41.0 | | | 5.4 | | 6.2* | 0.8 | 16.6 |
| Non-Lifeline | 61.8 | | | 12.0 | | 12.2 | 0.2 | 1.4 |
| Total Resale | 102.8 | | .1693 | 17.4 | .1795 | 18.4 | 1.0 | 6.1 |
| Total Sales | 7513.6 | | .2089 | 1569.9 | .2343 | 1760.1 | 190.2 | 12.1 |
| Other Revenue | | | | 1.6 | | 1.6 | | |
| Total Revenue | | | | 1571.5 | | 1761.7 | | |

1/ Residential Sales Adjusted by 9.4 MM Therms for G-10 and G-S Discounts.

2/ Percent Increase Based on Rate per Therm.

* Rounded Down.

(Red Figure)

# Reflects reduced revenue at present rates due to revised lifeline allowance.

A.57284, 57285 /ec/dz *

# TABLE G-3

## Gas Department Revenues

## Year 1978 Estimated

| Category | Present Rates MMS | Allocated Increase: General A-57285 MMS | Allocated Increase: Offset A-57978 MMS | Allocated Increase: Total MMS | At Adopted Rates MMS |
|---|---|---|---|---|---|
| Customer Months | 37.9 | 0 | 0 | 0 | 37.9 |
| Residential | | | | | |
| Lifeline | 229.5 | 20.0 | 18.1 | 38.1 | 267.6 |
| Non-Lifeline | 193.9 | 33.3 | 30.1 | 63.4 | 257.3 |
| Total Residential | 423.4 | 53.3 | 48.2 | 101.5 | 524.9 |
| Non-Residential | | | | | |
| Priority 1 & 2 | 405.6 | 35.4 | 32.0 | 67.4 | 473.0 |
| Priority 3 & 4 (G-50) | 202.0 | 10.7 | 9.6 | 20.3 | 222.3 |
| Priority 3 & 4 (G-52) | 82.4 | 0 | 0 | 0 | 82.4 |
| Priority 5 (G-57) | 19.9 | 0 | 0 | 0 | 19.9 |
| Priority 5 (G-55) | 381.3 | 0 | 0 | 0 | 381.3 |
| Total Non-Residential | 1091.2 | 46.1 | 41.6 | 87.7 | 1176.9 |
| Resale | | | | | |
| Lifeline# | 5.4 | 0.4 | 0.4 | 0.8 | 6.2 |
| Non-Lifeline | 12.0 | 0.1 | 0.1 | 0.2 | 12.2 |
| Total Resale | 17.4 | 0.5 | 0.5 | 1.0 | 18.4 |
| Total Sales | 1569.9 | 99.9 | 90.3 | 190.2 | 1760.1 |
| Other Revenue | 1.6 | | | | 1.6 |
| Total Revenue | 1571.5 | | | | 1761.7 |
| Percentage Allocation | | 52.5% | 47.5% | 100.0% | |

# Reflects reduced revenue at present rates due to revised lifeline allowance.

TABLE G-4

GAS DEPARTMENT

Residential Bill Comparisons

| Therms Billed | Present Rates | Adopted Rates | Increase Amount | Increase Percent |
|---|---|---|---|---|
| | | Summer (All Areas) | | |
| 0 | $ 1.20 | $ 1.20 | $ - | - % |
| 26 1/ | 4.88 | 5.50 | 0.62 | 12.7 |
| 52 | 9.57 | 12.00 | 2.43 | 25.4 |
| 104 | 20.12 | 26.95 | 6.83 | 33.9 |
| 200 | 41.14 | 63.04 | 21.90 | 53.2 |
| 400 | 84.94 | 138.24 | 53.30 | 62.8 |
| 700 | 150.64 | 251.04 | 100.40 | 66.6 |
| | | Winter - X Climatic Band 2/ | | |
| 0 | $ 1.20 | $ 1.20 | $ - | - % |
| 52 | 8.57 | 9.79 | 1.22 | 14.2 |
| 106 1/ | 16.22 | 18.71 | 2.49 | 15.4 |
| 212 | 39.12 | 45.21 | 6.09 | 15.6 |
| 400 | 80.29 | 101.61 | 21.32 | 26.6 |
| 700 | 145.99 | 191.61 | 45.62 | 31.2 |

1/ Lifeline allowance.

2/ Represents majority of customers in the PG&E service area. Bills in other climatic bands would vary depending on lifeline allowance.

We found in our concurrent decision in Application No. 55510 that Palo Alto is to be served by PG&E under a Schedule No. G-60 resale rate that will allow Palo Alto a 20 percent differential between gross revenues and purchased gas expense which is equivalent to $0.0458/therm of their purchases. Having established this underlying principle for determining the resale rate to Palo Alto, we believe it is equitable to apply similar percentage increases for PG&E's other resale customers also serving primarily high priority customers.

To establish the differential for Palo Alto, sales and revenues were developed based upon Palo Alto's lifeline proportion of 33.7 percent and lost and unaccounted for of 3.11 percent, PG&E's estimated sales volumes, and the adopted PG&E profile of sales to P-1 and P-2 customers in the manner shown below.

## PALO ALTO RATE DERIVATION

| | Proportion | Sales Volume Mdth | Adopted PG&E Rates $/th. | Equivalent Revenue M$ |
|---|---|---|---|---|
| I. Sales | | | | |
| Residential Lifeline | 33.7% | 1,428 | $ .1652 | $ 2,359 |
| Other Than Residential Lifeline | | | | |
| Tier II | 13.2 | 559 | .2500 | 1,398 |
| Tier III | 2.3 | 97 | .2750 | 267 |
| Tier IV | 4.1 | 174 | .3000 | 522 |
| Tier V | 1.7 | 72 | .3760 | 271 |
| Schedule G-1 N | 1.1 | 47 | .2750 | 129 |
| Priority 1 & 2 Nonresidential | 43.9 | 1,861 | .2554 | 4,753 |
| Subtotal - Other | 66.3 | 2,810 | | 7,340 |
| Total | 100.0 | 4,238 | | 9,699 |
| Customer Charge | | 254.2 | 1.20 | 305 |
| Total Rev. | | | | 10,004 |
| 80% of Rev. | | | | 8,003 ✓ |
| II. Purchases | | | | |
| LL = 1,428 Mdth x 1.0311 = | | 1,473 | .1540 | 2,268 |
| NLL = 2,810 " " | | 2,897 | .1979 | 5,733 |
| Total Purchases | | 4,370 | | 8,001 |

The principal portion of the increase was applied to the lifeline tier in the same proportion as was applied to PG&E, namely 16.6 percent. The small remainder represented an increase of 1.4 percent to nonlifeline P-1 and P-2 sales. This application of the increase provides similar treatment to lifeline quantities for PG&E's customers and lifeline quantities for customers served by resale entities, while still answering Palo Alto's concerns about its lack of industrial customers to absorb differential increases. Similar percentage increases to the lifeline and nonlifeline components of PG&E's other resale rates provide a reasonable overall increase of 6.1 percent to the resale customer class.

The treatment of Palo Alto as the bellwether for the resale class appears reasonable at this time. To a certain extent, Palo Alto's justification for a less than average increase also applies to Coalinga, C-P National, and Southwest. Their increases are 8.1 percent, 5.9 percent, and 6.6 percent, respectively, all below the system average of 12.1 percent. In future proceedings, this relationship may be continued, but only after scrutiny.

## Electric Rate Design

### Electric Rate Design Proposals

#### PG&E

PG&E's original electric rate proposal has been affected by the adoption of the electric rate stabilization plan in Decision No. 88262 issued December 20, 1977. It may be further affected by decisions in Application No. 57666, the time-of-use application for customers between 1,000-4,000 kw of demand, and in Case No. 10273, dealing with master-meter rates for mobile home parks. In consonance with Decision No. 88262, PG&E's electric rate proposal is to establish base rates as set forth in Chapter 3 of Exhibit 2, as amended by Exhibit 9, and to reduce its Energy Cost Adjustment (ECA) by an equivalent amount so that there will be no net increase in PG&E's gross revenues.

To achieve the offsetting Energy Cost Adjustment Clause (ECAC) reduction, PG&E proposes to revise two of the present three ECAC charges. The present ECA amounts are \$0.01003 for lifeline usage, \$0.02444 for the first rate block of nonlifeline residential usage, and \$0.02921 for all other usage subject to the ECA. PG&E proposes that the lifeline ECA of \$0.01003 remain unchanged. The ECA of \$0.02921 for nonresidential usage would be reduced by \$0.00219 per kilowatt-hour to \$0.02702. Also, the ECAs of \$0.02444 and \$0.02921 now applicable to residential service would be changed to a weighted average ECA of \$0.02651 for all nonlifeline residential usage.

PG&E in this proceeding has included proposed Schedule No. A-13, for time-of-use customers between 1,000-4,000 kw of demand. This assumes a transfer of customers from existing schedules, primarily Schedule No. A-13. Schedule No. A-22 is the subject of Application No. 57666, which is expected to authorize its implementation at current revenue levels prior to the decision in this application. Should that occur, the decision in this application should recognize the existing Schedule No. A-22 and increase the rates appropriately. If Schedule No. A-22 has not yet been authorized in Application No. 57666, then customers should continue on existing schedules (primarily Schedule No. A-13) at the proposed rate levels. The pattern of offsetting ECAC reductions described above would still be valid since the same amount of revenues would be generated under either Schedule No. A-22 or existing schedules.

A revenue reduction may result from Case No. 10273. The exact amount cannot be established until the decision is issued in that case. Based on the rate design in the preliminary report of the ALJ and on the special discounts recommended by the staff in that case, the electric revenue reduction in base rates would be $1,882,000 to reflect the effect of the change in the Public Utilities Code effected by Section 739.5. PG&E proposes that this reduction in revenues should be offset by a uniform increase of $0.00004 per kilowatt-hour in the base rates proposed in Chapter 3 of Exhibit 2. This change would not require any further adjustment in the ECAC rate.

PG&E also proposes, to include in LS-1, rates for lamps installed on company-owned poles (Class D), metal poles (Class E), and wood poles (Class F) installed solely for the luminaire, open LS-3 to new service and cancel LS-4. The company also proposes to charge for temporary discontinuance of service and to require a five-year contract for initial service.

Commission Staff

The staff witnesses' recommendations are summarized as follows:

1. The increase in base rates resulting from Decision No. 88262 should be considered as an interim increase and be replaced by the rate increase recommendations contained in Exhibit 74 which reflect changes in monthly charges, demand and commodity rates, and consolidation and elimination of certain schedules. ✓

2. The Commission should consider marginal costs in reaching its determination of revenue increases by class within the ranges shown in Exhibit 74, and further and more directly, consider marginal costs in the individual rates selected as recommended in Chapters 4, 5, and 6 of Exhibit 74.

3. Lifeline rates partake of a reasonable share of revenue increases resulting from this application.

4. The Commission gives recognition to the reduction in revenue requirements for this group (which result from a 5 percent demand reduction) through a reduction in the revenue increase to be assigned to this group. The reduction in revenue requirements for a 5 percent demand reduction is $3,818,000.

5. Domestic Schedules Nos. D-1 through D-5 should be consolidated into one Schedule No. D-1. Density zones should be eliminated and the present base rate structure should be inverted. The present three ECA factors applicable to domestic schedules should be consolidated into two factors (lifeline and nonlifeline). The air conditioning allowance and its reduced rates should apply only to the geographic areas proposed by the staff. The DM or master-metered schedule should be closed to new applicants and submetering for existing customers should be encouraged.

6. Electric bills should be fully itemized showing the appropriate kwhr lifeline allowance, lifeline and nonlifeline consumption, applicable rates, and the total bill. An explanation of each item should be added whenever possible.

7. General Service Schedules Nos. A-1 through A-5 should be consolidated into one Schedule No. A-1. Schedules Nos. A-16, H-1, P-1, P-3, and P-60 should be canceled and these customers should be transferred to the appropriate Schedule No. A-1 or Schedule No. A-12. The direct current Schedules Nos. A-15 and P-5 should be combined into one A-15. Schedule No. OL-1 should be closed to the installation of

any mercury vapor lamps for new customers. Schedule No. A-12 and the demand portion of Schedules Nos. A-41, P-3, and P-60 should be consolidated into one Schedule No. A-12, with the elimination of the 5,000-kwh block. The agricultural schedule should be revised to reduce the number of rates from seven to one.

8. Streets and Highway Lighting Schedules Nos. LS-60 and LS-61 should be canceled and the customers transferred to Schedule No. LS-1A. Schedules Nos. LS-3 and LS-4 should be combined into one Schedule No. LS-3. The format of Schedules Nos. LS-1 and LS-2 should be revised to include the nominal lamp rating in watts, lumens, line watts, and charges for different kinds of poles.

9. Incandescent lamps including 2,500 lumens and under should be allowed while lamps over 2,500 lumens should not be allowed for new customers under Schedule No. LS-2. PG&E should develop a program whereby incandescent lamps under Schedule No. LS-1 are replaced with more efficient lighting over a five-year period.

The following table shows the staff's range of revenue increase by class for 1978 test year:

| Class of Service | Staff Range of Revenue Increase 1/ | | Rate of Return by Class - Percent | | |
|---|---|---|---|---|---|
| | | | Present | With Staff Range of Increase | |
| | Low 2/ | High 2/ | Rates 3/ | Low 4/ | High 4/ |
| | (Dollars in Thousands) | | | | |
| Residential | $ 52,100 | $ 60,000 | 3.67% | 4.82% | 5.01% |
| Small Light & Pwr. | 13,900 | 24,800 | 14.55 | 15.85 | 16.93 |
| Medium Light & Pwr. | 35,500 | 37,700 | 13.26 | 15.57 | 15.70 |
| Large Light & Pwr. | 24,459 | 40,402 | 13.36 | 15.75 | 17.10 |
| Agricultural | 10,600 | 11,600 | 10.24 | 12.61 | 12.81 |
| Street Lighting | 1,493 | 3,400 | 8.96 | 9.94 | 11.03 |
| Subtotal | 138,052 | 177,902 | 8.48 | 10.33 5/ | 10.33 5/ |
| Public Authority | 700 | 918 | * | * | * |
| Railway | 331 | 805 | * | * | * |
| Interdepartmental | 418 | 447 | * | * | * |
| Other Oper. Rev. | 329 | 329 | * | * | * |
| Total Oper. Rev. | 139,830 | 180,401 | 8.48 | 10.33 5/ | 10.33 5/ |

* Rates of return not computed. To maintain a total rate of return of 10.33 percent total revenue increase for these four classes must equal total requested by utility.

1/ Excludes public authority, railway, interdepartmental, and other class revenue increases.

2/ No attempt is made to make low and high class revenue add to the amount requested by the utility.

3/ Monthly peak responsiblity method adjusted for ECAC energy cost allocation.

4/ Low and high rates of return for each class are computed assuming all other class revenues adjusted to yield $158,779.

5/ Utility requested rate of return.

California Retailers Association (CRA)

CRA proposes the establishment of a cost standard for lifeline rates as, according to CRA, it was obviously the intent of the legislature that lifeline rates should be lower than the average kilowatt-hour rate. It believes it is appropriate that lifeline rates should recover only out-of-pocket costs, but no profit to the utility. Thus, the revenue requirement standard for lifeline should be a zero rate of return.

CRA maintains that given that lifeline rates represent a subsidy even to users of greater quantities of electricity than the lifeline allowance, there is no longer any justification for perpetuating the traditionally lower rate of return for conventional residential service that is, the nonlifeline blocks of the residential rate schedules. Thus, it proposes that the rate of return to the nonlifeline residential service be set equal to the average rate of return for all nonlifeline services. These proposals yield a revenue increase from residential service which must then be distributed in the form of offsetting reductions to the nonresidential services. Although there are a variety of ways of distributing this revenue reduction, it proposes that it be based on the kwh energy sales to the respective classes and subclasses.

CRA does not believe that basic lifeline should be expanded to include air conditioning usage.

CRA's comments as regards the time-of-use rates which are now before this Commission are as follows:

> The Commission has designated PG&E's latest time-of-use rate, Schedule No. A-22, for separate consideration in Application No. 57666. However, as CRA's testimony in that proceeding indicates, the issues spill over into the revenue requirements of other services. Specifically, CRA believes that any revenue loss from the shift of

consumption from high-rated peak periods to lower rated partial and off-peak periods should be recovered from the entire spectrum of ratepayers rather than from those customers who happen to be on Schedule No. A-22. Furthermore, CRA observes that the energy charge in Schedule No. A-22, applicable to customers between 1,000 and 4,000 kw, is unreasonably higher than that found in Schedule No. A-17, applicable to customers over 4,000 kw. Correction of this infirmity would require revision of both schedules. For these reasons, the Commission may have to consider PG&E's time-of-day rates in reaching a decision in this proceeding.

The following table compares CRA's class revenue requirement and rate of return with PG&E's proposal:

Class Revenue, Rate of Return
(000 omitted)

| | CRA | PG&E | |
|---|---|---|---|
| Residential | $115,921 | $102,124 | 5.8 % |
| Agriculture | 21,691 | 29,209 | 11.75 |
| Street Lighting | 8,196 | 8,398 | 10.04 |
| Light & Power | | | |
| Small | 73,327 | 75,182 | 15.52 |
| Medium | 112,510 | 117,310 | 14.75 |
| Large | 84,941 | 90,359 | 15.73 |
| Net for Classes | 422,584 | 422,582 | |

City and County of San Francisco (city)

According to city, because of rate stabilization there should be no increase to any customer. In addition, city believes no party has justified, on a ratemaking cost-of-service basis, the elimination of zones.

California Manufacturers Association (CMA)

CMA contends that domestic service under 440 kilowatt-hours per month is rendered at a loss of $31 million to PG&E with a negative rate of return.

Further, CMA contends that residential customers are not being given the proper incentives to conserve by the existing rates or those proposed by PG&E or the Commission staff in their proposed electric rate designs; and while some lifeline "subsidy" may be appropriate, an appropriate lifeline rate should provide at least a zero rate of return rather than a negative rate of return for the lifeline class.

CMA believes that authorized rate increases to industrial customers are actually higher in relation to the average increase in electric costs in California than has been the case in the nation as a whole, thus causing a deterioration in the competitive position of California industry with respect to competition from out of California. Also, CMA asserts that the higher marginal costs being considered as alternative rates for industrial schedules may actually impede energy conservation by industry.

CMA's rate design proposal - simply stated - is: Do not raise any industrial rate but place all of the increase on the residential class.

City of Oakland (Oakland)

According to Oakland, the Commission should adopt its street lighting recommendations as follows:

> First, the proposed rates would bring some order to rate schedules which have grown incoherent. The present street lighting rate structure is the result of many years of PG&E advice letter filings. To my knowledge, the structure has never been examined overall for consistency and fairness. The present schedules allow PG&E to overcharge street lighting energy sales and use the revenue to subsidize company maintenance and owning operations. The result has been the vast enlargement of company-owned street lighting plant. Cities and other agencies which use street lighting have been led to depend upon PG&E for street lighting facilities rather than consider contractor service or agency ownership and maintenance. Competition has been controlled to the company's benefit and to the users' detriment. The Oakland proposed rates would charge all street lighting customers properly and fairly for energy use. In addition, ownership and maintenance costs would be charged only to customers using the service.
>
> Second, the proposed rates would encourage the use of energy efficient lighting. The energy used for street lighting in the PG&E system is 493 million kwh per year. (PG&E 1978 test year estimate.) The same amount of light could be provided with energy efficient lights which would consume only 222 million kwh per year (55 percent reduction).

Oakland further maintains that energy rates for traffic signals have been unusually high compared to rates for other users. In the PG&E rate proposal, the base energy rate for traffic signals is 3.19¢/kwh. With 1978 test year ECAC added, the rate would be 5.63¢/kwh. Oakland contends that the load characteristic for traffic signal service is much better than that for most other service classes. and that PG&E's proposed rate is not supported.

The Oakland proposed base rate is 1.966¢/kwh. With 1978 test year ECAC added, the traffic signal energy rate will be 4.41¢/kwh. Traffic signal energy is metered; therefore, a $1.50/mo. service charge is required. The Oakland proposed allocation of cost to traffic signal service provides revenue amounting to 4.59¢/kwh which is sufficient to recover all fuel, operation, and maintenance expenses for the service, and also allows the return on investment asked by PG&E.

If the Oakland proposed rate is accepted, traffic signal customers will find a reduction in their energy bills.

Airco, Inc. (Airco) and General Motors Corporation (GM)

The position of GM and Airco is that if the Commission grants PG&E the full amount of the increase requested, it would recommend that $115 million of that increase be assigned to the residential class:

$11 million to the small light and power class;
$16 million to the medium light and power class;
$11 million to large light and power;
$4 million to the agricultural class; and
$3 million to the street lighting class.

The balance should be spread among public authority, railway, interdepartmental, and other revenue categories.

If the Commission finds a smaller increase than the amount requested, then they recommend all of those increases should be scaled downward proportionately.

Adopted Electric Rates

In an effort to normalize the electric rate aftermath of the recent two-year drought (causing wide fluctuations in energy costs of PG&E and the ECAC balancing account), we have been attempting to stabilize revenues and rates. We synchronized base rate increases with ECAC rate reductions in Decision No. 88262. And we conclude that it is reasonable to continue our policy of rate stabilization in this proceeding. By Decision No. 89318 in Application No. 58033 (PG&E ECAC) we are reducing ECAC rates by $200 million (0.446 c/kwh). In reflecting that reduction along with the base rates increased by this order, it is our general goal that no overall rate increase (combined base rates and ECAC rates) will result for the various customer classes.

Another objective, as we authorize rates for PG&E, is to eliminate declining block rates. Declining block rates are inconsistent with the goal of encouraging conservation and slowing the need for costly (financially and environmentally) new generating units. The problem with declining block rates is that the last energy units used (and which could possibly be saved) are less expensive, and the customer does not receive as meaningful an economic signal when he does conserve.

A third objective is to more fully utilize than has been done in previous decisions the concept of marginal cost, and the marginal costs developed in this proceeding. Marginal costs are the one set of costs which, when translated into prices, serve to promote the most efficient use of scarce resources and most usefully indicate to consumers the costs they are imposing on the system. Our movement in the direction of marginal cost pricing represents a major effort in pursuit of the goal of conservation, and in promoting the most efficient use and allocation of resources. The utility and the staff should increase their efforts in developing marginal costs and rates based on marginal costs for future proceedings.

After a careful review of the evidentiary record, <u>Residential Rates</u>, we will adopt the staff's recommendation to eliminate various density zone rates and consolidate domestic Schedules Nos. D-1 through D-5 into one Schedule No. D-1. This is done to simplify PG&E's rate structure and enable the public to understand information disseminated about electric rate design and how conservation will affect their electric bills. Further, by establishing a uniform $1.75 per month fixed domestic customer charge, we can price units of energy use so that utility bills are usage sensitive. These objectives are very much in the public interest as California and the nation move toward a conservation oriented energy ethic.[9/]

We agree with staff testimony that the bill formats for PG&E should be revised to provide sufficient information to enable customers to readily follow the calculation of their bills. The bill should, at a minimum, separate the customer's monthly charge from the commodity charge so that the customer is aware of the price being paid for increased usage. This is especially pertinent for residential customers although the concept of providing sufficient information is applicable to all customer classes.

<u>Lifeline Rates</u>

Consistent with the policy discussed above, we will eliminate residential nonlifeline declining block rates and establish one uniform flat rate above the lifeline quantity which is higher than the lifeline rate to encourage conservation. Also, we find it is reasonable to simplify lifeline commodity rates which now vary with existing zones and establish one uniform lifeline rate. We also will eliminate existing declining block lifeline quantity rates.

The staff's proposed air conditioning allowance for two climate areas is reasonable and will be adopted. However, the months for which the rate will apply will be extended from the staff's recommended period of June through September to May through October to be consistent with our recent Decision No. 88651 (Lifeline Investigation, Phase II).

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9/ We note that density zone rates were historically supposed to be cost of service related. However, the record reflects that it tends to cost PG&E more to serve Zone D-1 (with the highest density) and Zone D-5 than it does Zones 2, 3, and 4 (Exhibit 74, p.4-2 and related testimony). Thus, San Francisco's contention that existing density zone rates should be retained because they are cost of service related does not have merit.

The rate effect of consolidating lifeline rates will result in base rate increases to some lifeline customers. These particular increases cannot be offset by ECAC reductions because ECAC reductions are being applied only to nonlifeline usage.

The following tabulation compares our adopted domestic base and ECAC rates with the rates in effect at the date of this decision. The following Table E-1 shows how the increases compare to the presently effective rates authorized for electric department jurisdiction operations:

TABLE E-1

| Present Schedule No. | Lifeline Allowance | Monthly kWh Usage | $ At Present Rates | $ At Adopted Rates | Increase $ | Increase % |
|---|---|---|---|---|---|---|
| D-1 | 240 | 240 | 7.62 | 7.89 | 0.27 | 3.5 |
| | | 300 | 10.16 | 10.50 | .34 | 3.3 |
| | | 500 | 19.32 | 19.18 | (.14) | (.7) |
| | | 1,000 | 42.21 | 40.89 | (1.32) | (3.1) |
| | | 1,290 | 55.49 | 53.48 | (2.01) | (3.6) |
| | | 1,500 | 65.11 | 62.60 | (2.51) | (3.9) |
| | | 2,000 | 88.00 | 84.31 | (3.69) | (4.2) |
| D-1 | 1040 | 240 | 7.62 | 7.89 | .27 | 3.5 |
| | | 300 | 9.14 | 9.43 | .29 | 3.2 |
| | | 500 | 13.92 | 14.55 | .63 | 4.5 |
| | | 1,000 | 25.86 | 27.35 | 1.49 | 5.8 |
| | | 1,290 | 38.26 | 39.23 | .97 | 2.5 |
| | | 1,500 | 47.88 | 48.35 | .47 | 1.0 |
| | | 2,000 | 70.77 | 70.06 | (.71) | (1.0) |
| D-5 | 240 | 240 | 9.08 | 7.89 | (1.19) | (13.1) |
| | | 300 | 11.86 | 10.50 | (1.36) | (11.5) |
| | | 500 | 21.13 | 19.18 | (1.95) | (9.2) |
| | | 1,000 | 44.03 | 40.89 | (3.14) | (7.1) |
| | | 1,290 | 57.31 | 53.48 | (3.83) | (6.7) |
| | | 1,500 | 66.92 | 62.60 | (4.32) | (6.5) |
| | | 2,000 | 89.82 | 84.31 | (5.51) | (6.1) |
| D-5 | 1040 | 240 | 9.08 | 7.89 | (1.19) | (13.1) |
| | | 300 | 10.84 | 9.43 | (1.41) | (13.0) |
| | | 500 | 16.74 | 14.55 | (2.19) | (13.1) |
| | | 1,000 | 28.68 | 27.35 | (1.33) | (4.6) |
| | | 1,290 | 41.08 | 39.23 | (1.85) | (4.5) |
| | | 1,500 | 50.70 | 48.35 | (2.35) | (4.6) |
| | | 2,000 | 73.59 | 70.06 | (3.53) | (4.8) |

(Negative Amount)

Medium and Large Light and Power Demand Charges

Presently under Schedules Nos. A-12 and A-13 of the medium and large light and power categories, respectively, the customer's bill is a function of his energy demand and commodity use. The billing demand charge depends on the customer's usage pattern. If use is concentrated (and the customer puts maximum demand on the utility's system capacity), the billing for demand increases. Those customers who have relatively low billing demand charges, but who may consume a relatively large quantity of energy, contribute toward a higher utility load factor.

As a customer's load factor increases, a larger portion of his use is spread over semi-peak and off-peak periods (thereby decreasing peak load and the utility's need for additional generating capacity). We believe the staff's proposed A-12 and A-13 rate schedules will encourage these customers to achieve a higher load factor. For example, Schedule No. A-13 customers who have a load factor of 14 percent or below will pay the highest rate, those with a load factor between 14 percent and 41 percent will pay a lower commodity rate, and those with a 41 percent plus load factor will pay the lowest commodity rate. We are of the opinion that it is reasonable to assume that the customer with a load factor of 14 percent or less is consuming almost all of the energy during peak periods. Also, we believe the charges in Schedules Nos. A-12 and A-13 ordered herein are consistent with our policy announced in Decision No. 85559, Case No. 9804, which is to eliminate declining block rates and encourage time-of-use pricing. In the meanwhile, these rates will be replaced over time by time-of-use rates as time-of-use metering is implemented for more and more customers. The rate structure we have adopted is in the time-of-use direction (as a load management measure) and will encourage non-peak use.

Small Light and Power

Neither PG&E nor the staff proposed simplification of the blocking or rate structure for small light and power customers served under Schedule No. A-1.

However, we believe we should make changes to Schedule No. A-1 similar to those adopted for domestic customers, and for substantially the same reasons. The existing multiple rate zones are eliminated, as are the present three declining blocks. The customer charge will be a uniform $1.75 per month and a uniform commodity rate of .03¢/kwh will be applied under the new consolidated Schedule No. A-1. These charges will result in an estimated test year base rate revenue reduction of $21.6 million. However, this reduction is reasonable to bring rates for these customers in line with those of other customers; traditionally, their rates have exceeded the unit rates of other classes of service. The following Table E-2 illustrates the change in typical customer bills resulting from our rate restructuring and ECAC reductions:

# TABLE E-2

## Pacific Gas and Electric Company
## BILL COMPARISON

| Monthly Usage kWh | $ At 4/1/78 Rates | $ Adopted A-1 | Increase $ | Increase % |
|---|---|---|---|---|
| **Present Schedule A-5 vs Adopted A-1** | | | | |
| 100 | 10.29 | 6.95 | (3.34) | (32.5) |
| 300 | 26.88 | 17.36 | (9.52) | (35.4) |
| 500 | 43.47 | 27.77 | (15.70) | (36.1) |
| 800 | 68.35 | 43.37 | (24.98) | (36.5) |
| 1,000 | 82.34 | 53.78 | (28.56) | (34.7) |
| 1,500 | 117.31 | 79.80 | (37.51) | (32.0) |
| 3,000 | 207.22 | 157.84 | (49.38) | (23.8) |
| 6,000 | 372.04 | 313.93 | (58.11) | (15.6) |
| **Present Schedule A-1 vs Adopted A-1** | | | | |
| 100 | 7.79 | 6.95 | (.84) | (10.8) |
| 300 | 20.38 | 17.36 | (3.02) | (14.8) |
| 500 | 32.97 | 27.77 | (5.20) | (15.8) |
| 800 | 51.85 | 43.37 | (8.48) | (16.4) |
| 1,000 | 63.84 | 53.78 | (10.06) | (15.8) |
| 1,500 | 93.81 | 79.80 | (14.01) | (14.9) |
| 3,000 | 178.72 | 157.84 | (20.88) | (11.7) |
| 6,000 | 343.54 | 313.93 | (29.61) | (8.6) |

(Negative Amount)

Agricultural and Medium and Large Light and Power Rates

We will continue the multiple block rate structure to encourage higher load factors for these customers (pending implementation of time-of-use rates), while adjusting tail block rates so they will be at a more reasonable level for the customer who attains a high load factor.

For agricultural users we will adopt PG&E's proposal, which was supported by the staff, that consolidates seven existing demand charge blocks into one and which consolidates twenty-one energy rate blocks into three. The lower service and monthly horsepower change proposed by the staff is reasonable and will be adopted.

We continue to pursue rate incentives that are designed to reduce or shift PG&E's summer agricultural demand. Electricity for agricultural pumping places considerable demand on PG&E's summer generating capacity. Combined with air conditioner use during the warmest periods of the day, agricultural pumping significantly contributes to the highest peak demand days. Experimental time-of-use rates are now in effect and available to encourage off-peak agricultural pumping. We believe PG&E should be directed to advise all agricultural customers of the time-of-use rate availability. If demand for time-of-use metering exceeds immediate capacity, PG&E should give high priority to expanding the availability of agricultural time-of-use metering. In future proceedings we will consider the need for mandatory time-of-use rates for agricultural pumping.

The staff's recommendation for consolidating medium light and power schedules as described herein are adopted. Schedule No. A-17 will be retitled Schedule No. A-23.

Street Lighting Rates

PG&E proposed a painting charge for street lighting poles. Presently under Schedule No. LS-1 normal maintenance is performed by the utility. We conclude that street lighting rates adequately cover utility costs for normal maintenance, and we will not adopt PG&E's proposal.

We will adopt some of PG&E's proposed changes to the special conditions of Schedule No. LS-1. It is reasonable to adopt a special charge when a customer orders service to be discontinued. Such a charge makes PG&E whole for service discontinuance expense and, to a small extent, contributes some return for its investment in the facilities, which during disconnection will produce no revenue.

We approved lower rates when company-owned incandescent and mercury vapor lamps are converted to high pressure sodium vapor (HPSV) lamps, PG&E Advice Letter No. 669-E, filed May 5, 1978. Those rates will reduce the bills of customers served under Schedules Nos. LS-1 and OL-1, and it is reasonable to adopt that rate as the base rate for HPSV lamps. The staff recommends higher rates for incandescent and mercury vapor lamps, and we believe the rates for those lamps should be higher to encourage conversion to more efficient HPSV in the interest of promoting energy conservation.

PG&E's recommendation, which the staff supported, to modify traffic control Schedule No. TC-1 is reasonable and will be adopted. However, the commodity rate will be lowered to the level adopted for the new consolidated Schedule No. A-1 (see preceding discussion on small light and power rates). That reduction brings these rates into line with other rates, as recommended by the city of Oakland.

The following Table E-3 illustrates how the adopted rate design will generate the electric department's revenue requirement.

# TABLE E-3

Pacific Gas and Electric Company
Electric Department

1978 ADOPTED SALES AND REVENUE

| Line No. | Customer Class | Adjusted for: $ Discounts Sales GWh 2/ (A) | Base Revenue $M 2/ at 1/1/78 (B) | ECAC + PUPP: Revenue $M at 4/1/78 (C) | Total Revenue $M at 4/1/78 (D) | Total Rate ¢/kWh 4/1/78 (E) | Base Revenue Increase $M (F) | Base Revenue Increase ¢/kWh (G) | ECAC Revenue Increase $M (H) | ECAC Revenue Increase ¢/kWh (I) | Net Change in Revenue $M (J) | Net Change in Revenue ¢/kWh (K) | Total Revenue $M (L) | Total Average Rate ¢/kWh (M) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Residentials | | | | | | | | | | | | | |
| 1 | Lifeline | 8,707 | $ 209,242 | $ 83,239 | $ 292,481 | 3.359 | $ (1,307) | (0.015) | $ (0) | - | $ (1,307) | (0.015) | $ 291,174 | 3.344 |
| 2 | Non-Lifeline | 9,651 | 169,930 | 250,897 | 440,827 | 4.568 | 1,307 | .014 | (16,876) 1/ | (0.456) | (15,569) | (.472) | 395,258 | 4.096 |
| 3 | Total Residential | 18,358 | 379,172 | 334,136 | 733,308 | 3.994 | 0 | 0 | (16,876) | (.255) | (16,876) | (.255) | 686,432 | 3.739 |
| | Light & Power | | | | | | | | | | | | | |
| 4 | Small | 4,398 | 160,081 | 116,503 | 276,584 | 6.289 | (21,551) | (.490) | (19,615) | (.446) | (41,166) | (.936) | 235,418 | 5.353 |
| 5 | Medium | 11,744 | 246,009 | 311,099 | 577,108 | 4.744 | 25,991 | .233 | (52,378) | (.446) | (26,387) | (.216) | 531,721 | 4.528 |
| 6 | Large | 13,374 | 176,448 | 354,277 | 530,725 | 3.968 | 27,062 | .202 | (59,649) | (.446) | (32,586) | (.244) | 498,139 | 3.725 |
| 7 | Total Light & Power | 29,515 | 582,535 | 781,879 | 1,384,417 | 4.623 | 32,502 | .110 | (131,641) | (.446) | (99,132) | (.336) | 1,265,278 | 4.287 |
| 8 | Public Authority* | 2,233 | 4,267 | 7,417 | 11,684 | 4.173 | 564 | .201 | (1,249) | (.446) | (685) | (.245) | 10,999 | 3.928 |
| 9 | Agricultural | 3,714 | 73,084 | 98,384 | 171,468 | 4.617 | 3,493 | .094 | (16,564) | (.445) | (13,071) | (.352) | 158,397 | 4.265 |
| 10 | Street Lighting | 503 | 22,255 | 13,324 | 35,579 | 7.073 | 1,686 | .335 | (2,243) | (.446) | (551) | (.111) | 35,022 | 6.963 |
| 11 | Railway | 266 | 2,494 | 7,046 | 9,540 | 3.586 | 524 | .197 | (1,186) | (.446) | (662) | (.249) | 8,878 | 3.338 |
| | Interdepartmental | | | | | | | | | | | | | |
| 12 | Construction & Clearance | 35 | 792 | 927 | 1,719 | 4.911 | 92 | .263 | (156) | (.446) | (64) | (.183) | 1,655 | 4.729 |
| 13 | Other Operations | 103 | 2,138 | 2,728 | 4,866 | 4.724 | 233 | .226 | (459) | (.446) | (226) | (.219) | 4,640 | 4.505 |
| 14 | Total Interdepartmental | 138 | 2,930 | 3,655 | 6,585 | 4.772 | 325 | .236 | (615) | (.446) | (290) | (.210) | 6,295 | 4.562 |
| 15 | Subtotal | - | 1,086,740 | 1,245,841 | 2,332,581 | 4.420 | 39,094 | .074 | (200,374) | (.385) | (161,280) | (.306) | 2,171,301 | 4.114 |
| 16 | Other Operating Revenues | - | 33,827 | 33,827 | 33,827 | - | 94 | - | - | - | 94 | - | 33,921 | - |
| 17 | Total CPUC | 54,728 | 1,120,567 | 1,279,668 | 2,366,408 | 4.420 | 39,188 | .074 | (200,374) | (.360) | (161,186) | (.306) | 2,205,222 | 4.114 |

(Negative Figure)

* Proportional adjustment as authorized in contracts.

1/ Includes revenue decrease due to air-conditioning allowance.

2/ PG&E Exhibit No. 96, p. A-3.

Findings

1. A reasonable return on PG&E's estimated 1978 total common equity is 12.83 percent.

2. A 12.83 percent return on total common equity results in a 9.50 percent rate of return to be applied to the rate bases of PG&E's electric department (California jurisdictional) and gas department.

3. In Decision No. 86281 we proposed that all expenses of the applicant's Diablo Canyon nuclear projects be excluded in the adopted test year and be considered in a separate Diablo rate base offset proceeding. The Operations Division's staff results of operation in this proceeding excluding all costs related to Diablo Canyon including interest deductions and ad valorem taxes (both for book and as income tax deductions), and investment tax credit progress payments is reasonable and consistent with our prior Decision No. 86281. Further, it is reasonable that at the time of inclusion of Diablo Canyon in rate base the proper treatment of all investment tax credits, including progress payments, will be considered (and the recorded book value of the facility will be appropriately adjusted).

4. The estimated adopted test year results of operations for PG&E's gas and electric departments, as set forth in Tables I, II-A, and II-B in the body of this opinion, are reasonable.

5. To have an opportunity to earn its authorized rate of return for the electric department, PG&E needs an annual income in gross revenue requirement in the amount of $39,188,000, excluding ECAC revenues.

6. To have an opportunity to earn its authorized rate of return for the gas department, PG&E needs an annual increase in gross revenue requirement in the amount of $99,329,000.

7. PG&E has included, and the Commission has adopted, $4.7 million test year conservation expense for customer incentives (water heater blankets and shower heads). Those incentive programs should be implemented now, subject to modification or termination after the rehearing of Decision No. 88551, Case No. 10032.

8. PG&E's conservation efforts, while not as vigorous and imaginative as they could be, are adequate and a rate of return reduction is not warranted.

9. In Decision No. 84902 we said: "We expect utilities to explore all feasible cost-effective means of conservation, including... providing customers with detailed, intelligible information on appliance energy use by brand name ('Shoppers Guide')..." PG&E has distributed this information only to appliance dealers and customers specifically requesting it.

10. PG&E needs to review all its options for repowering existing generating facilities (including hydroelectric plants), expanding facility modification and maintenance efforts that can improve generating efficiency and reliability.

11. PG&E needs to reveiw and catalog all auxiliary power and cogeneration sources in its service area and determine their availability and potential to contribute power during PG&E's highest demand periods.

12. PG&E needs to prepare future electricity supply and investment plans for a period of a minimum of 20 years.

13. It is reasonable and in the public interest to direct PG&E to undertake a management audit. The Commission should approve the scope of the management audit.

14. The proposal of Southwest and Palo Alto (resale customers of PG&E) that their respective resale rates be adjusted to exclude PG&E's conservation expense is not in the public interest. PG&E's conservation efforts benefit these resale customers (and ultimately their customers) as well as all California energy utility customers.

15. Gas rate design proposals submitted by Kerr-McGee and CMA, emphasizing high fixed monthly customer charges, are inconsistent with a conservation oriented rate design, which places emphasis on pricing units of energy use to give customers a clear economic message that conservation equates to significant utility bill savings.

16. It is reasonable to establish Palo Alto's rate (Schedule No. G-60), so that Palo Alto has a $0.0458/therm differential above the cost of purchased gas on every dollar of sales, using PG&E's general service rates as a basis for determining Palo Alto's revenue.

17. The gas rates authorized in Appendix B hereto are reasonable.

18. The electric rates authorized in Appendix C hereto are reasonable.

19. Marginal cost based rates promote the more efficient use of resources and provide more accurate price signals to consumers. The utility and the staff should increase their efforts in developing marginal costs and rates based on marginal costs.

20. There is a need for PG&E to pursue rate incentives that are designed to reduce or shift PG&E's summer agricultural customer electricity demand.

21. PG&E should undertake a revision of its current billing formats in order to ensure that customers are provided with all of the information necessary to allow them to understand the calculation of their bills.

22. It is reasonable to make the base rate increases authorized herein conditional on PG&E's concurrently making effective rate reductions resulting from recently adopted Article XIII-A of the California Constitution (Proposition 13). PG&E has filed Advice Letters Nos. 106-G and 687-E estimating reduced cost of service in the amount of $17,740,000 for its gas department and $43,876,000 for its electric department. PG&E has established a tax initiative balancing account pursuant to our OII No. 19.

23. All pending motions taken under submission and not ruled on should be denied.

24. The following order should be effective the date of signature because there is an immediate need for rate relief.

Conclusions

1. PG&E should be authorized to file revised gas rates as set forth in Appendix B, which are designed to:

   a. Produce $99,329,000 in additional revenues based on 1978 test year adopted results of operation.

   b. Produce $90,300,000 in additional revenues to compensate for increased purchased gas expense, pursuant to Decision No. 89317 in Application No. 57978.

PG&E should, concurrently effective with the above increases, reduce gas rates by $17,740,000 annually (pursuant to PG&E's Advice Letter No. 106-G) to pass on the estimated benefits of Article XIII-A of the California Constitution to consumers.

PG&E should file within 60 days in Case No. 10032 contingency plans for alternate conservation activities in the event customer incentive conservation programs are not approved after rehearing of Decision No. 88551.

2. PG&E should be authorized to adjust electric rates as set forth in Appendix C, which are designed to do the following:

   a. Increase base rates by $39,188,000 based on test year 1978 adopted results of operation.

   b. Reduce ECAC rates by $208,577,000, pursuant to Decision No. 89318 in Application No. 58033.

PG&E should, concurrently effective with the above increases, reduce electric rates by $43,876,000, pursuant to its Advice Letter No. 687-E, to pass on the estimated benefits of Article XIII-A of the California Constitution (Proposition 13).

3. PG&E should be directed to review and study options for resource planning.

4. PG&E should be directed to undertake a management audit under the supervision of the Commission staff.

5. PG&E should be directed to distribute a "Shopper's Guide" comparing the efficiency of domestic electric refrigerator units.

6. Electric rates authorized to be collected subject to refund in Decision No. 88262, Application No. 57289, should no longer be collected subject to refund.

## O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) shall review all its options for repowering existing generating facilities (including hydroelectric plants) and for expanded facility modification and maintenance efforts that can improve efficiency and reliability. PG&E shall also assess the cost-effectiveness of these options. PG&E shall report to the Commission on its findings within one hundred eighty days from the date of this order with a progress report after ninety days. PG&E's efforts along these lines will be reviewed in an investigation being instituted concurrently with this decision. PG&E shall further proceed to implement all cost-effective maintenance programs as soon as possible after completing this review and shall incorporate all cost-effective repowering options into its resource plan or justify to this Commission its decision for not doing so.

2. PG&E shall review and catalog all existing auxiliary power sources in its service area and all potential future auxiliary power and cogeneration projects and their availability to contribute power during its high demand periods. This review shall include an assessment of the economics, institutional arrangements, maintenance and fuel requirements, and possible cost-effective incentives necessary to enable it to call upon such auxiliary facilities as peaking capacity for its system. PG&E shall report to the Commission on its findings within one hundred eighty days from the date of this order with a progress report after ninety days.

3. PG&E shall, by April 15, 1979, prepare and submit a twenty-year electric supply plan reflecting energy conservation and all cost-effective alternate sources of energy. Complete information should be provided on loads and resources, estimated capital and operating costs, and financial and rate impacts for each year of the twenty-year period.

4. PG&E shall undertake a management audit, conducted by independent consultants. Before consulting contracts are awarded and the audit is begun, the Executive Director shall submit to the Commission, for its approval, the specific areas of inquiry the management audit will cover.

5. PG&E shall advise, within sixty days from the date of this order, all customers who are eligible for experimental time-of-use rates for agricultural pumping of the availability of such time-of-use rates. If PG&E cannot provide time-of-use metering facilities to all eligible agricultural customers requesting such facilities by February 1, 1979, it shall advise the Commission the reasons why it cannot. PG&E is directed to give high priority to implementing time-of-use rates for agricultural customers. And if PG&E cannot provide such facilities to all agricultural customers requiring it by February 1, 1979, it shall explain the measures it is taking to give this undertaking high priority.

6. PG&E shall distribute, at least once every 18 months, to each of its residential customers a brochure listing energy efficient refrigerators, freezers, and refrigerator-freezer combinations. The brochure shall compare appliances with similar features, listing specific information by brand name, model, size in cubic feet, kilowatt-hour usage per month, and average estimated annual operating cost. The first distribution of this brochure shall be made within ninety days from the effective date of this order.

7. PG&E shall, in consultation with the staff, undertake to revise its bill formats in such manner as is directed by the staff. The revised formats shall provide customers with the information necessary for an understanding of the bill calculation.

8. PG&E shall advise all agricultural electric customers of the availability of time-of-use rates. PG&E shall furthermore give high priority to expansion of time-of-use rates and metering for agricultural electric customers.

9. PG&E is authorized to immediately implement its insulation incentive programs as planned.

10. PG&E is hereby directed to file within sixty days, in Case No. 10032, contingency plans for alternate conservation activities, with expenses budgeted at an annual rate of $4.7 million in the event that incentive programs are terminated upon rehearing of Decision No. 88551.

11. PG&E is authorized to file with this Commission revised schedules for gas and electric rates as set forth in Appendices B and C hereto on or after the effective date of this order. The revised tariff schedules shall become effective five days after filing. The increase in base rates authorized herein is conditioned on PG&E's concurrently filing tariff schedules making the reductions it proposed in its Advice Letters Nos. 106-G and 687-E, reducing nonlifeline gas rates on an equal cents-per-therm basis by $17,740,000 annually and nonlifeline electric rates on an equal cents-per-kilowatt-hour basis by $43,876,000.

12. All motions in these proceedings not heretofore ruled on are denied. ✓

13. Electric rates collected subject to refund pursuant to Decision No. 88262, Application No. 57289, shall no longer be collected subject to refund. ✓

The effective date of this order is the date hereof.

Dated at San Francisco, California, this 6th day of SEPTEMBER, 1978.

I will file a dissent.
William Symons, Jr.

I will file a written concurrence
Vernon L. Sturgeon

Robert Batinovich
President

Vernon L. Sturgeon
Richard D. Gravelle
Claire T. Dedrick
Commissioners

APPENDIX A

## LIST OF APPEARANCES

Applicant: Malcolm H. Furbush, Robert Ohlbach, and William H. Edwards, Attorneys at Law, for Pacific Gas and Electric Company.

Protestants: Mike Franey, for Concerned Consumer Committee; Rev. Fred Wilken, for Consumers Protective Service; Cherylyn Smith, for People for Safe Energy; and Shendl Tuchman, for People Against Nuclear Power.

Interested Parties: Thomas M. O'Connor, City Attorney, by Leonard L. Snaider, Deputy City Attorney, and Robert R. Laughead, P.E., for City and County of San Francisco; Glen J. Sullivan, Attorney at Law, for the California Farm Bureau Federation; Gordon E. Davis and William H. Booth, Attorneys at Law, for California Manufacturers Association; Susan L. Paulus, Attorney at Law, for Owens-Corning Fiberglas Corporation; John G. Lyons, Attorney at Law, for Stuart Morshead; David B. Roe, Thomas J. Graff, and Christopher H. Schroeder, Attorneys at Law, for the Environmental Defense Fund; Robert Spertus and David Tishman, Attorneys at Law, and Sylvia Siegel, for TURN; Henry R. MacNicholas, Attorney at Law, for Airco, Inc.; Earl R. Sample, for Southern California Edison Company; William L. Knecht, Attorney at Law, for California Association of Utility Shareholders; Georges H. Shers, H. W. Carmack, and Dick Urbanick, for City of Oakland; John L. Mathews, Attorney at Law, for the Executive Agencies of the United States; Anne Mester and Jonathan Blees, Attorneys at Law, for California State Energy Resources Conservation and Development Commission; Scott A. Stephens, for Building Owners & Managers Association; Randy Baldschun and Marilyn Norek Taketa, Attorney at Law, for City of Palo Alto; Boris H. Lakusta, David J. Marchant, and Jerry J. Suich, Attorneys at Law, for California Hotel & Motel Association, Western Mobilehome Association, and Collier Carbon & Chemical Corporation; Allen B. Wagner, Attorney at Law, and Harry Winters, for The Regents of the University of California; James P. Bennett, Attorney at Law, for Kerr-McGee Chemical Corporation; Thomas S. Knox and William Bogaard, Attorneys at Law, for California Retailers Association; Philip A. Stohr and Richard R. Gray, Attorneys at Law, for General Motors Corporation; Peter Kuhn, for himself; and Richard D. DeLucc, Attorney at Law, for Air Products & Chemicals, Inc.

Commission Staff: James S. Rood, Mary Carlos, and Jasper Williams, Attorneys at Law, Martin Abramson, P.E., John D. Quinley, P.E., and Kenneth Chew, C.P.A.

Pacific Gas and Electric Company

GAS RATES

Applicants rates and charges to be at the level set forth in this appendix.

| Schedules G-1[1]/GS | Per Meter Per Month |
|---|---|
| Customer Charge . . . . . . . . . . . . . . . . . . . . . | $1.20 |

Commodity Charge

G-1B, GS-B

| | |
|---|---|
| First 26 therms, per therm . . . . . . . . . . . . . . . . . . | $0.1652 |
| Next 26 therms, per therm . . . . . . . . . . . . . . . . . . | 0.2500 |
| Next 26 therms, per therm . . . . . . . . . . . . . . . . . . | 0.2750 |
| Next 26 therms, per therm . . . . . . . . . . . . . . . . . . | 0.3000 |
| Over 104 therms, per therm . . . . . . . . . . . . . . . . . . | 0.3760 |

G-1H, GS-H

| | Summer All Bands | Winter Climatic Band W | X | Y | Z | | |
|---|---|---|---|---|---|---|---|
| First | 26 | 81 | 106 | 141 | 166 | therms, per therm . . . . . . . . | $0.1652 |
| Next | 26 | 81 | 106 | 141 | 166 | therms, per therm . . . . . . . . | 0.2500 |
| Next | 26 | - | - | - | - | therms, per therm . . . . . . . . | 0.2750 |
| Next | 26 | over 162 | 212 | 282 | 332 | therms, per therm . . . . . . . . | 0.3000 |
| Over | 104 | - | - | - | - | therms, per therm . . . . . . . . | 0.3760 |

G-1N

All deliveries, per therm . . . . . . . . . . . . . . . . . . . . . . . . . . $0.2750

Schedule G-M

Rates and winter tiers as for Schedule G-1

Schedule G-2[1/][2/]

All deliveries, per therm . . . . . . . . . . . . . . . . . . . . . . . . . . $0.2554

Schedule G-50

All deliveries, per therm . . . . . . . . . . . . . . . . . . . . . . . . . . $0.2520

Schedules G-52, G-55, G-57

All deliveries, per therm . . . . . . . . . . . . . . . . . . . . . . . . . . $0.2290

1/ Pacific Gas and Electric Company shall file a separate Schedule No. G-2, with applicable conditions, for non-residential Priority 1 and 2 service previously rendered under Schedule No. G-1.

2/ Schedules G-2 and G-30 shall be increased commensurately.

| Resale Schedules | G-60 | G-61 | G-62 | G-63 |
|---|---|---|---|---|
| First (Lifeline Volume), | 33.7% | 53.9% | 38.8% | 44.0% |
| per therm | .1540 | .1555 | .1548 | .1518 |
| Excess, per therm (Demand charge eliminated) | .1979 | .1991 | .1984 | .1966 |

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Applicant's electric rates, charges, and conditions are changed to the level or extent set forth in this appendix.

Schedule D-1

| Rates: | Per Meter Per Month |
|---|---|
| Customer Charge | $1.75 |
| Energy Charge | |
| Lifeline Usage 1/ | .01604 per kWh |
| Non-Lifeline Usage | .02139 per kWh |

1/ The following quantities of electricity are to be billed at the rates for lifeline usage:

| End Use | Code | Monthly KWh Allowance for Climatic Bands* W | X | Y | Z |
|---|---|---|---|---|---|
| Basic Allowance** | B | 240 | 240 | 240 | 240 |
| Basic plus Water Heating | W | 490 | 490 | 490 | 490 |
| Basic plus Space Heating | | | | | |
| Summer (May 1 to Oct. 31) | H | 240 | 240 | 240 | 240 |
| Winter (Nov. 1 to April 30) | H | 790 | 1040 | 1360 | 1660 |
| Basic plus Space and Water Heating | | | | | |
| Summer (May 1 to Oct. 31) | C | 490 | 490 | 490 | 490 |
| Winter (Nov. 1 to April 30) | C | 1040 | 1290 | 1610 | 1910 |
| Non-Lifeline | N | 0 | 0 | 0 | 0 |

Energy used in excess of the lifeline allowances will be billed at the non-lifeline rates, continuing from the quantity reached by the lifeline allowance.

* Climate Bands are described in the presently effective Preliminary Statement.

** Includes lighting, cooking and refrigeration.

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Lifeline Electrical Air Conditioning Allowance

The allowance for Areas 1 and 2 for single-family dwelling are 280 kWh and 230 kWh, respectively, and for multi-family dwelling 170 kWh and 140 kWh, respectively. These allowances apply to central or window electric air conditioners or evaporative coolers for qualified customers in the months of May through October.

Area 1 shall consist of the following territory:

| County | Elevation Range |
|---|---|
| Fresno | Under 3,500' |
| Kern | All |
| Kings | All |
| Madera | Under 4,000' |
| Mariposa | Under 3,500' |
| Merced | All |
| Tulare | Under 3,500' |

Area 2 shall consist of the following territory:

| County | Elevation Range |
|---|---|
| Amador | Under 3,000' |
| Butte | Under 3,000' |
| Calaveras | Under 3,000' |
| Colusa | All |
| El Dorado | Under 3,000' |
| Glenn | Under 3,000' |
| Nevada | Under 3,000' |
| Placer | Under 3,000' |
| Sacramento | All |
| San Joaquin | All |
| Shasta | Under 2,000' |
| Solano | All* |
| Stanislaus | All |
| Sutter | All |
| Tehama | Under 2,500' |
| Tuolumne | Under 3,500' |
| Yolo | All |
| Yuba | All |

* Sacramento Division territory only.

A. 57284, 57285 FG/fc



Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

| Schedule No. A-1 | Per Meter Per Month |
|---|---|
| Customer Charge: | $1.75 |

Energy Charge (in addition to the Customer Charge):

All kWh, per kWh $0.03 per kWh

Polyphase Service: The single phase rate plus $1.25 per meter per month.

Revise minimum charge of the rate to include the customer charge and $1.50 per month per kW of connected welder load and/or per horsepower of polyphase connected load.

| Schedule No. A-12 | Per Meter Per Month |
|---|---|
| Demand Charge: | |
| First 50 kW of billing demand or less | $120.00 |
| Over 50 kW of billing demand, per kW | 2.05 |
| Energy Charge (in addition to the Demand Charge): | |
| First 150 kWh per kW of billing demand, per kWh | .01609 |
| Next 150 kWh per kW of billing demand, per kWh | .01400 |
| All excess, per kWh | .01288 |

| Schedule No. A-13 | Per Meter Per Month |
|---|---|
| Demand Charge: | |
| First 1,000 kW of billing demand | $2,658.00 |
| Over 1,000 kW of billing demand | 2.12 |
| Energy Charge (in addition to the Demand Charge): | |
| First 100 kWh per kW of billing demand, per kWh | .01451 |
| Next 200 kWh per kW of billing demand, per kWh | .00991 |
| All excess, per kWh | .00791 |

A. 57284, 57285 FG/fc *



Pacific Gas and Electric Company
RATES - ELECTRIC DEPARTMENT

| Schedule No. A-15 | Per Meter Per Month |
|---|---|
| Customer Charge: | $1.75 |
| Energy Charge (in addition to the Customer Charge): All kWh, per kWh | $0.06 |

Minimum Charge: The Customer Charge, except where motors aggregating more than 5 hp are connected, in which case the total minimum charge will be $1.60 per month per hp.

| Schedule No. A-18 | Per Meter Per Month |
|---|---|
| Demand Charge: | |
| On-Peak, per kW of maximum demand, but not less than $7,000 per month | $1.40 |
| Off-Peak, per kW of maximum demand in excess of the On-Peak demand | 0.35 |
| Energy Charge: | |
| All kWh, per kWh | 0.00829 |

| Schedule No. A-23 (Formerly A-17) | Per Meter Per Month | |
|---|---|---|
| | Period A | Period B |
| Customer Charge: | $715.00 | $715.00 |
| Demand Charge: | | |
| On-Peak, per kW of maximum demand | 4.20 | 2.80 |
| Plus Partial Peak, per kW of maximum demand | 0.35 | 0.35 |
| Plus Off-Peak, per kW of maximum demand | No Charge | No Charge |
| Energy Charge: | | |
| On-Peak, per kWh | 0.01045 | 0.01045 |
| Plus Partial Peak, per kWh | 0.00845 | 0.00845 |
| Plus Off-Peak, per kWh | 0.00645 | 0.00645 |

| Schedule No. OL-1 | Per Lamp Per Month |
|---|---|
| Mercury Vapor | |
| 175 watts | $5.80 |
| 400 watts | 8.47 |
| High Pressure Sodium Vapor | |
| 70 watts | 5.75 |
| 100 watts | 6.25 |
| 150 watts | 6.65 |
| 200 watts | 7.40 |

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Special Contracts - SLAC and Ames

(a) United States Atomic Energy Commission, Stanford Linear Accelerator Center (SLAC), under contract dated January 10, 1963.

(b) National Aeronautics & Space Agency, Ames Laboratory, Moffett Field (Ames under contract dated February 12, 1975).

The special contract rates for interruptible service to USAEC, Stanford Linear Accelerator Center and NASA, Ames Laboratory, Moffett Field are as follows:

| | Rate |
|---|---|
| Demand Charge: | |
| On-Peak Demand, per kW per month | $1.10 |
| Off-Peak Demand, per kW per month | .36 |
| Energy Charge (to be added to the Demand Charge): | |
| First 300 kWh per kW of Demand, per kWh | .0051 |
| All over 300 kWh per kW of Demand, per kWh | .0051 |
| Energy component of minimum charge, per kWh | .00721 |

Special Contract - U.C. Berkeley

Firm and curtailable service is provided to Regents of the University of California Berkeley Campus, and Radiation Laboratory, under contract dated October 7, 1965. The contract provides in paragraph 3 that the contract rate is to be adjusted to reflect changes in Schedule No. A-13 rates. Based on 1978 estimated sales and proposed Schedule No. A-13, the annual increase will be $363,000.

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Special Contract - City and County of San Francisco
Streetlight Service

Streetlighting service to City and County of San Francisco. The contract with the City is subject to corresponding changes "if the Public Utilities Commission of the State of California shall fix rates that are higher or lower ... for like conditions of service." Based on total annual revenues of $645,000 under this contract, the additional increase will be $26,000 or 4% per year.

Special Contract - City and County of San Francisco
Supplementary Service

Supplementary service is furnished to the City and County of San Francisco under contract dated March 14, 1945, as amended. The rates for the facility charges are subject to change from time to time to reflect the rate of return as currently authorized by the Commission. The rate of return authorized under this order will increase the revenue by $68,000.

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Special Contract - BART

Bay Area Rapid Transit District (BART) - Traction and station and miscellaneous power, under contract dated May 31, 1968, Decision No. 74675, dated September 11, 1968.

The special contract rates for traction, station, and miscellaneous power to Bay Area Rapid Transit District are as follows:

| | Rate |
|---|---|
| Traction Power | |
| Demand Charge: | |
| Per kW of billing demand | $ - 2.15 |
| Energy Charge: | |
| Per kWh | .00524 |
| Station and Miscellaneous Power | |
| Demand Charge: | |
| Per kW of billing demand | 2.15 |
| Energy Charge: | |
| Per kWh | .00524 |
| Special Facility Charge | |
| Per month | 22,800.00 |

It is estimated that the proposed rates will increase revenues from BART by $524,000.

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. LS-1

| Class | | All Night Rates Per Lamp Per Month | | | | | | Half-Hour Adjustment |
|---|---|---|---|---|---|---|---|---|
| | | A | B | C | D | E | F | |
| **Nominal Lamp Rating Incandescent Lamps*** | | | | | | | | |
| Watts | Lumens | | | | | | | |
| 58 | 600 | $ 2.908 | | | | | | $0.029 |
| 92 | 1,000 | 3.170 | | | | | | 0.047 |
| 189 | 2,500 | 4.746 | $ 3.726 | | | | | 0.095 |
| 295 | 4,000 | 5.695 | 4.674 | | | | | 0.148 |
| 405 | 6,000 | 6.696 | 5.673 | | | | | 0.204 |
| 620 | 10,000 | 8.986 | 7.993 | | | | | 0.311 |
| **Mercury Vapor Lamps** | | | | | | | | |
| Watts | Lumens | | | | | | | |
| 100 | 3,500 | $ 4.673 | $ 3.936 | $3.028 | $ 8.13 | $ 7.65 | $ 6.01 | $0.047 |
| 175 | 7,500 | 5.135 | 4.423 | 3.755 | 8.37 | 8.15 | 6.50 | 0.074 |
| 250 | 11,000 | 5.922 | 5.184 | 4.525 | 10.14 | 9.00 | 7.89 | 0.107 |
| 400 | 21,000 | 7.683 | 6.776 | 5.945 | | 10.96 | 9.42 | 0.170 |
| 700 | 37,000 | 12.065 | 10.138 | | | 15.10 | 14.72 | 0.289 |
| 1,000 | 57,000 | 14.851 | 12.810 | | | 18.20 | 17.46 | 0.410 |

* Service for incandescent lamps is limited to those installations in service as of September 21, 1975.

Note: Rates shown are the base rates.

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. LS-1 (Contd.)

| Class | | | All Night Rates Per Lamp Per Month | | | | | | Half-Hour Adjustment |
|---|---|---|---|---|---|---|---|---|---|
| | | | A | B | C | D | E | F | |
| **High Pressure Sodium Vapor Lamps** | | | | | | | | | |
| **120 Volts** | | | | | | | | | |
| Lamp Watts | Line Watts | Average Initial Lumens | | | | | | | |
| 70 | 85 | 5,800 | $ 5.75 | $5.00 | $4.10 | $8.60 | $8.35 | $6.75 | $0.025 |
| 100 | 121 | 9,500 | 6.25 | 5.50 | 4.23 | 8.85 | 8.65 | 7.25 | 0.035 |
| 150 | 176 | 16,000 | 6.65 | 5.90 | 4.75 | 9.20 | 9.25 | 7.65 | 0.052 |
| **240 Volts** | | | | | | | | | |
| Lamp Watts | Line Watts | Average Initial Lumens | | | | | | | |
| 70 | 98 | 5,800 | $ 5.75 | | | | | | $0.029 |
| 100 | 144 | 9,500 | 6.25 | | | | | | 0.043 |
| 150 | 206 | 16,000 | 6.65 | | | | | | 0.061 |
| 200 | 236 | 22,000 | 7.40 | $6.65 | $5.50 | | $10.10 | $9.65 | 0.079 |
| 250 | 321 | 25,500 | 7.95 | 7.20 | 6.10 | | 10.70 | 10.25 | 0.096 |
| 400 | 487 | 46,000 | 9.30 | 8.55 | 7.40 | | 12.00 | 11.55 | 0.145 |

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. LS-1 (Contd.)

Pole Charge:

For Class A and B pole installations using other than wood poles that were installed entirely at Utility expense, customer will pay a monthly pole charge of $3.15; or $2.60 for installations made prior to September 21, 1975 (closed to new installations).

For Class A and B pole installations using other than wood poles where the customer elected to pay a nonrefundable amount equal to the estimated additional cost of installation over that of a basic installation, the customer will pay a monthly pole charge of $1.35; or $0.00 for installations made prior to September 21, 1975. (Closed to new installations.)

SPECIAL CONDITIONS

1. Type of Service: The Utility reserves the right to supply either "multiple" or "series" service. Series service to new lights will only be made where it is practical from the Utility's engineering standpoint to supply them from existing series systems.

2. Annual Operating Schedule: The above rates for All-Night service assume an average of approximately 11 hours operation per night and apply to lamps which will be turned on and off once each night in accordance with a regular operating schedule agreeable to the customer but not exceeding 4,100 hours per year.

3. Operating Schedules Other Than All-Night: Rates for regular operating schedules other than full All-Night will be the All-Night rate plus or minus, respectively, the half-hour adjustment for each half-hour more or less than an average of approximately 11 hours per night. This adjustment will apply only to lamps on regular operating schedules of not less than 1,095 hours per year, or 3 hours per night, nor more than 4,500 hours per year.

4. Description of Service Provided:

Class A

Utility owns and maintains luminaire, control facilities, support arm, and service wiring on its existing distribution pole, and all lights formerly served under Schedule LS-1, Class A, as of August 22, 1978.

Schedule No. LS-1 (Contd.)

SPECIAL CONDITIONS (Contd.)

Class B

Utility owns and maintains luminaire, control facilities, support arm, pole or post, foundation and service connection and where customer has paid the estimated installed cost of the luminaire, support arm and control facilities (applicable only to installations in service as of September 6, 1978).

Class C

Utility owns and maintains its standard luminaire, control facility, overhead service and internal support arm wiring as required (ownership of pole or post, support arm and foundation by customer). Available only where customer-owned poles comply with the Utility's engineering and operating requirements.

Class D

Utility owns and maintains its standard post top luminaire, control facility, internal post wiring, standard galvanized steel post (20 ft. mounting height or less) and foundation where customer pays for the estimated installed cost of the post, support arm (if any) and foundation.

Class E

Utility owns and maintains its standard luminaire, control facility, internal pole wiring, service connection, galvanized steel pole and foundation where the customer has paid to the Utility the estimated installed cost of the pole, support arm and foundation.

Class F

Utility owns and maintains a standard luminaire, control facility, support arm, and service connection on its wood pole or post, installed solely for the luminaire.

5. Rearrangement of Facilities: At the customer's request the Utility will make changes to or rearrangement of existing facilities at the customer's expense.

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. LS-1 (Contd.)

SPECIAL CONDITIONS (Contd.)

6. Underground Service: The applicant at his expense shall perform the necessary trenching, backfill and paving, and shall furnish and install all necessary conduit and substructures including substructures for transformer installations if necessary, for street lights only, in accordance with the Utility's specifications. Upon acceptance by the Utility, ownership of the conduit and substructures shall vest in the Utility.

The Utility, at its expense, will furnish and install the underground service conductor to the handhole of each street light pole where the length of the service is 100 circuit feet or less per luminaire, as measured from the point of connection to the point of secondary supply. For service lengths in excess of 100 feet the applicant shall pay to the Utility the material cost of the conductors in excess of 100 circuit feet.

7. Ownership: All facilities installed under this schedule except for the Class "C" customer-owned pole or post, support arm and foundation shall vest in the Utility.

8. Maintenance: The Utility shall exercise reasonable care and diligence in maintaining Utility-owned facilities. Maintenance will be performed as an accommodation on a customer-owned Class "C" pole or post, arm and foundation, at the customer's expense, where customer is unable to obtain the service elsewhere. Where the Utility experiences or expects to experience maintenance costs exceeding its normal maintenance expense, resulting from but not limited to vandalism, or unusual non-standard design or pole, post, or luminaire, the Utility may require the customer to pay excess maintenance costs as may be necessary.

9. Special Equipment: Luminaires, poles, posts and other equipment, requested by a customer or applicant, in addition to or in substitution for the Utility's standard galvanized steel poles, galvanized steel posts, photocell controls and equipment, will be provided if such equipment meets the Utility's engineering and operating standards and if the customer or applicant pays the cost difference between the equipment normally provided by the Utility and the equipment requested by the customer or applicant, plus an additional continuing monthly payment equal to 1% of the cost difference. This provision is also applicable to special optical filters, shields or other special hardware required or requested by the applicant or any governmental agency having jurisdiction. At the request of the customer or applicant the Utility will install special equipment entirely at the Utility's expense provided the customer agrees to pay a continuing monthly payment equal to 2% of the cost difference.

Pacific Gas and Electric Company
RATES - ELECTRIC DEPARTMENT

Schedule No. LS-1 (Contd.)

SPECIAL CONDITIONS (Contd.)

10. Line Extensions: Where the Utility determines that it is necessary to extend its electric distribution lines to serve only a street light or a street lighting system, the applicant shall advance, subject to refund in accordance with Electric Rule 15, the estimated installed cost of such line extension, exclusive of service conductors (and transformer if required), under the provisions of Special Condition 9. The Utility may waive the foregoing line extension provisions where the extension is estimated to be of nominal cost and where not more than one pole and one span of overhead line is required to reach the Utility designated connection point, or in the case of underground facilities, where the first-service delivery point is no greater than 300 feet from the Utility designated connection point. The cost difference used in calculating the continuing monthly payment as specified in Special Condition 9 will be reduced by an amount equal to any Electric Rule 15 refund, and the continuing monthly payment shall be adjusted accordingly.

11. Temporary Discontinuance of Service: (Fixture remains in place) At the request of the customer the Utility will temporarily discontinue service to individual luminaires provided the customer pays a facility charge equal to the all-night rate, adjusted to 0 burning hours under the provisions of Special Condition 3, plus the estimated cost to disconnect and reconnect the light.

12. Contract: Service to each light installation shall be for an initial contract term of 5 years and shall automatically continue thereafter from year to year. The initial term shall commence when permanent service is first rendered or within 90 days of when the lights are first ready for service, whichever occurs first.

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. LS-2

Rate Per Month

| Operating Schedule -- Nominal Lamp Rating: | | | A<br>Utility supplies energy and switching* service only.<br>All-Night | B<br>Utility supplies the energy, switching* and maintenance service for lamps and glassware.<br>All-Night | C<br>Utility supplies the energy, switching* and maintenance service for entire system including lamps and glassware.<br>All-Night | A, B and C Half-Hour Adjustment |
|---|---|---|---|---|---|---|
| **Incandescent Lamps** | | | | | | |
| Watts | Lumens** | | | | | |
| 92 | 1,000 | | $1.024 | $ 1.724 | $ 2.384 | $0.047 |
| 189 | 2,500 | | 2.080 | 2.93 | 3.59 | 0.095 |
| 295 | 4,000 | | 3.264 | 4.164 | 4.824 | 0.148 |
| 405 | 6,000 | | 4.480 | 5.38 | 6.04 | 0.204 |
| 620 | 10,000 | | 6.848 | 7.868 | 8.528 | 0.311 |
| 860 | 15,000 | | 9.504 | 10.644 | 11.30 | 0.432 |
| **Low Pressure Sodium Vapor Lamps** | | | | | | |
| Lamp Watts | Line Watts | Average Initial Lumens | | | | |
| 35 | 68 | 4,800 | $0.456 | - | - | - |
| 55 | 90 | 8,000 | 0.589 | - | - | - |
| 90 | 148 | 13,500 | 0.969 | - | - | - |
| 135 | 205 | 21,500 | 1.349 | - | - | - |
| 180 | 255 | 33,000 | 1.672 | - | - | - |
| **High Pressure Sodium Vapor Lamps** | | | | | | |
| 120 Volts | | | | | | |
| Lamp Watts | Line Watts | Average Initial Lumens | | | | |
| 70 | 85 | 5,800 | $0.55 | $ 1.36 | $ 2.02 | $0.025 |
| 100 | 121 | 9,500 | 0.78 | 1.64 | 2.30 | 0.035 |
| 150 | 176 | 16,000 | 1.14 | 2.00 | 2.66 | 0.052 |
| 240 Volts | | | | | | |
| Lamp Watts | Line Watts | Average Initial Lumens | | | | |
| 70 | 90 | 5,800 | $0.646 | $ 1.236 | $ 1.896 | $0.029 |
| 100 | 144 | 9,500 | 0.95 | 1.540 | 2.20 | 0.043 |
| 150 | 205 | 6,000 | 1.349 | 1.939 | 2.599 | 0.061 |
| 200 | 236 | 22,000 | 1.729 | 2.349 | 3.009 | 0.079 |
| 250 | 321 | 25,500 | 2.109 | 2.729 | 3.389 | 0.096 |
| 400 | 497 | 46,000 | 3.192 | 3.812 | 4.472 | 0.145 |
| **Metal Halide Lamps** | | | | | | |
| Lamp Watts | Line Watts | Average Initial Lumens | | | | |
| 400 | 460 | 30,000 | $3.078 | - | - | $ .140 |
| 1,000 | 1,118 | 90,000 | 7.334 | - | - | .333 |
| **Mercury Vapor Lamps** | | | | | | |
| Lamp Watts | Line Watts | Average Initial Lumens | | | | |
| 100 | 124 | 3,500 | $1.032 | $ 1.512 | $ 2.172 | $0.047 |
| 175 | 198 | 7,500 | 1.632 | 2.112 | 2.772 | 0.074 |
| 250 | 285 | 11,000 | 2.352 | 2.962 | 3.622 | 0.107 |
| 400 | 452 | 21,000 | 3.744 | 4.354 | 5.014 | 0.170 |
| 700 | 766 | 37,000 | 6.36 | 7.500 | 8.16 | 0.289 |
| 1,000 | 1,088 | 57,000 | 9.024 | 10.234 | 10.894 | 0.410 |

* Switching Service is closed to new installations.
** Latest published information should be consulted on best available lumens.
** Services for incandescent lamps over 2,500 lumens will be closed to new installations after September 6, 1978.
Note: Rates shown are the base rates.

A. 57284, 57285 FG/fc



Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

Schedule No. LS-2 (Contd.)

Revise Special Conditions 8 and 9 to read as follows:

8. Systems Owned in Part by the Utility: Where, after the date this provision is first effective, the Utility installs and thereafter owns and maintains any portion of the fixtures, poles, circuits, or other facilities that comprise customer's street lighting system, an additional monthly charge of 2% of the Utility's estimated installed cost of such facilities will be made. If such facilities were installed prior to the date this provision is first effective, the additional monthly charge will be 1-3/4% of such cost.* Customer or others may elect to pay the Utility's estimated installed cost of such facilities, in which event the additional monthly charge will be 1% of such cost.

9. Line Extensions: Where, after the date this provision is first effective, the Utility extends its electric lines to serve customer's street lighting system, an additional monthly charge of 2% of the Utility's estimated installed cost of such line extension, exclusive of service connection (and transformer, if required) furnished under Special Conditions 1, 4 and 5 will be made. If such extension was installed prior to the date this provision if first effective, the additional monthly charge will be 1-3/4% of such cost.* If customer elects to advance the Utility's estimated installed cost of such extension, the additional monthly charge will be 1% of such cost. The Utility may waive the foregoing provisions where the extension is estimated to be of nominal cost and where not more than one pole and one span of line is required. If such extension, or any portion thereof, is utilized to serve new separately metered permanent load for which an excess free length of line is allowed under Rule No. 15, such cost to be used in determining the additional monthly charge will thereafter be reduced in proportion to the relative length of excess free-footage allowance for the new load, if any, as compared to the length of the original extension. If an advance has been made as provided above, and if under Rule No. 15, an excess free-footage allowance remains after the new load is installed, all or part of the advance will be refunded without interest to the customer. These refunds will be computed by converting the amount of the advance to an amount per foot and multiplying the excess free footage by this unit per foot. Such refunds, if any, will be made following the connection of such new load. If such extension is part of a series of extensions, on any of which an advance is still refundable, refunds due from new load will be made in turn as provided in Rule No. 15. No payment will be made in excess of the orignal amount advanced.

* Except for facilities installed prior to February 13, 1971, in which case the monthly charge will be 1½%.

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

| Schedule No. LS-3 | Per Meter Per Month |
|---|---|
| **Rates** | |
| Service Charge: | $ 3.00 |
| Energy Charge: | |
| First 150 kWh per KW of billing demand | 0.0393 |
| Over 150 kWh per KW of billing demand | 0.0120 |
| Switching Charge*: | |
| For each circuit switched | 3.25 |

* In certain localities where utility supplies service from 120/208 volt, wye-connected, polyphase line in place of 240 volt service.

Special Conditions

Special conditions of the existing Schedule LS-3 will be replaced by the special condition of Schedule LS-4.

Pacific Gas and Electric Company

RATES - ELECTRIC DEPARTMENT

| Schedule No. TC-1 | Per Meter Per Month |
|---|---|
| Service Charge: | |
| For each service connection | $1.50 |
| Energy Charge: | |
| All kWh, per kWh | 0.03 |

| Schedule No. PA-1 | Per Meter |
|---|---|
| Service Charge, per customer per month | $2.50 |
| Per hp or kW, per month | 0.60 |
| | Rates per kWh per hp or kW per year |
| Energy Charge (in addition to the Service Charge): | |
| First 1,000 kWh per hp or kW, per kWh | .01692 |
| Next 1,000 kWh per hp or kW, per kWh | .01341 |
| Over 2,000 kWh per hp or kW, per kWh | .01052 |

Decision on General Rate Increase Application of Pacific Gas and Electric Company

COMMISSIONER WILLIAM SYMONS, JR., Dissenting

Government is supposed to house disinterested officials "who see the big picture" and respond by long range planning. Too frequently, however, Government houses the fellows with their eyes on the next election. So the planning is really short-run — to get by the next two years or the next two months. Recently, in its energy utility decisions, the California Public Utilities Commission has employed gimmickry and short-run considerations to an unbelievable extent. Unfortunately, today's order carries on in the same vein.

The tragic harm caused by regulation for the short-run is often unnoticed until much later, when the decision-makers have moved on, and John Q. Citizen is left holding the bag. This must not happen in California.

I

The Commission Evades Problems in Gas Pricing Which Have Reached Crisis Proportions.

The most critical failure in today's decision is the Commission's "band-aid" non-solution to the severe crisis caused by last year's surprise restructuring of natural gas prices (D.87585, July 12, 1977).

Examine the most important portion of today's general order, that is, the changes in base rates. The big changes have been in gas. (Changes on the electric side, due to ECAC are large, but not as significant. Rates are lowered as they were raised, therefore, not changing rate structure). The following table identifies the changes in PG&E's rates. It can be seen that the "big dollar" changes in base rates occur in natural gas:

| | BASE RATE CHANGES | ECAC CHANGES | CHANGES Attributable to Prop. 13 | CHANGES Postponed Until January 1, 1979 |
|---|---|---|---|---|
| GAS | $190 Million Increase | | $18 Million decrease | Approximately $38 Million Increase; to be Postponed to next GCAC |
| ELECTRIC | $39 Million Increase | $209 Million Decrease due to End of Drought | $44 Million Decrease | |

To issue this general rate case, but evade the severe gas problem, is bad regulation. General rate cases are infrequent but important. The general rate case is characterized by broad participation and full issue investigation. For this reason, the general rate case decision is the proper vehicle to correct serious problems recognized to be building up in the system.

In PG&E's case, it is apparent from the record that the Commission's hasty and ill-conceived rate redesign of last summer has had severe detrimental effects on the company, the customers, and the economy. Rates that commerce and business must pay are now among the highest and most unfair in the country. These are rates which deter relocation of new industry and jobs to California. These rates competitively disadvantage existing California producers. They are rates which force inflation in consumer prices.

Social ratemaking schemes of the past two years and life-line overruns have so distorted rates in California that disbursing less-than-cost energy is wide spread and common. To compensate, prices to remaining customers have been jacked-up enormously. These prohibitively high rates have caused a substantial segment of PG&E's historical customers to use alternate fuel and prematurely leave the system. An unheard-of gas glut has developed in California. Underground storage has been stuffed to historical highs.1/ A revenue crisis for the utility resulted.

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1/ A.57978 TR Vol. 1, p 56. The Volume of gas in storage for PG&E at the beginning of the summer period (when storage usually begins), July 1, 1978, stood at 170 billion cubic feet; 70% above PG&E's own storage capacity. PG&E has made additional arrangements for storage. PG&E estimates deliveries exceeding sales such as to cause storage to reach 211 billion cubic feet by December 1979. (Vol. 1, pg 95). This approximates nearly one half of the annually gas supply received from Canadian sources.

California already is attracting notoriety for its oddball rates:

> "In brief, the subsidy to lifeline users of natural gas approaches incredibility. For PG&E, cost-of-service studies on the peak month basis introduced into a 1978 rate case show large industry paying rates for natural gas which equate to a 42 per cent rate of return on natural gas sales to the residential class is minus 2 per cent".2/

> "The original intent of 'lifeline rates' in California is so deformed that it reminds one of the adage: 'Nothing is worthless, it can serve as a horrible example.'"3/

Consistent with the record developed in this case, as well as the evidence incorporated from companion hearings in A.58078, the Commission needs to undertake immediate restructuring of rates with a reallocation of revenue requirements to effect parity with cost of service. California needs a return to sanity in gas pricing.

Instead, the Commission cynically avoids coming to grips with the crisis, allowing this malignancy to fester and grow. This continues in the unsavory practice of the past year: put off the day-of-reckoning as long as possible.

2/ "California's Lifeline Policy", Dr. Albin J. Dahl, Public Utilities Fortnightly, Aug. 31, 1978, p.20.

3/ "Utility Rates under the National Energy Act, Quo Vadis," Daniel J. Reed, Public Utilities Fortnightly, July 20, 1978, p. 12.

The Commission grasps one expedient after another:

1) First, \$52.4 million in refunds due PG&E customers were expropriated. Instead of being refunded, the money was used to defer rate changes and buy gas in 1978. (D.88261, Dec., 20, 1977). Those monies are now nearly exhausted.

2) Next, the CPUC tried to stop the loss in sales by conspiring with the Air Resources Board to require large customers to buy gas regardless of price. That course raised such a furor that it has been shelved for the time being.

3) The CPUC replaced the mechanism of the "PGA" (Purchased Gas Adjustment) with a "GCAC", (Gas Cost Adjustment Clause). The PGA is an offset procedure. Costs and rates rise simultaneously. The PGA is designed to match cost of gas increases with increases revenue rates so there is no lag time.

The new GCAC is a recorded system. It uses an accounting accrual method. Undercollection will be accrued to be repaid with rate increases at a future date. \$38 million in gas rate increases are thus postponed till the new year.

4) The CPUC seizes upon property tax reductions that may occur in 1979 and uses them now. (This mechanism for premature application of tax reductions is discussed in detail later).

5) In its series of non-solutions, the Commission next concocted what must appear to consumers as the regulatory equivalent of the "Death Star". It's name is "S.A.M." The

Commission's starting "Supply Adjustment Mechanism" insulates utilities (but not customers) from the effects of the precipitous fall-off in gas sales. (D.88835, May 1, 1978). S.A.M. guarantees the companies a margin on sales, whether sales are made or not. The money to make the utilities whole in the case of non-sales will come from adding a S.A.M. surcharge to customers bills. An increase as large as $85 million dollars for PG&E was forseen to begin with the new year.

Today's decision goes an extreme further:

6) The Commission establishes discriminatory pricing within a class of similar customers. The old G-50 schedule for P-3 and P-4 customers is split. 29% of the customers form a new group: G-52. The new G-52 customers are to be charged a cheaper gas rate even though they use the gas for identically the same use as the remaining G-50 customers. The only operative distinction is between the "haves" and the have-nots". Customers with capability to use alternate fuels Numbers 5 and 6 are treated to the lower rates of 22.9¢/therm. Customers without, are "treated" to a rate increase of 25.2¢/therm. As numerous parties to the record and the staff indicate, there is no reasonable basis to justify this discrimination. It is as wrong as if the PUC had ordered fares for bus service lower to a man who owns a car, and higher to a man without one. When we regulate monoplies, our first duty under the CPUC Code is to prevent discrimination among customers — not to establish it.

I have two other comments on today's gas rate changes: First, it is unlikely that the discriminatory G-52 rate will effect a solution to the lost revenue problem because the Commission only sets the scheme halfway into operation. PG&E filed for a 20¢/therm rate. PG&E's survey shows that P-3 and P-4 customers able to switch to Number 6 fuel purchase account for 36 billion cubic feet in gas sales annually. At 22.9¢/therm expected loss in sales is 24 billion cubic feet. At 20¢/therm only 9 billion cubic feet of sales was predicted to be lost. The selection of the 22.9¢/therm figure by the PUC makes the success its "G-52 solution" questionable. If the "G-52 solution" fails to reverse the fall-off in sales the remaining customers can expect S.A.M. surcharge beginning the new year to be considerably increased.

Second, I note that lifeline rates have been raised from 14.2¢ to 16.5¢/therm. I do not think this fact alone justifies us to proclaim that the majority has finally seen the light. With such an extremely over-burdened non-residential class there is really very little choice left to the majority as to where to place these rate increases. One should soberly note that the average commodity charge for gas has risen substantially over the last two years. The increased lifeline charge of 16.5¢ is still substantially below the 18¢/therm system average commodity cost of gas. 60% of residential gas is sold at these less-than-cost lifeline rates. So one realizes that the enormous subsidy burden of massive welfare still weighs too heavily down upon the system.

II

The Electric Base Rate Increase Is Not Disbributed Equitably

Today's order grants $39 million in base rate increases. This is an overall 3% system increase, yet:

- residential goes up 0%
- agricultural goes up 5%
- there is 7% relief to small light and power
- medium light and power goes up 11% or $27 million
- large light and power goes up 15%, also $27 million. This is 5 times the system average rate increase.

Such a pattern of rate increases completely ignores cost-of-service. It ignores the punitively high rate of return already paid by large business and industry. Such heavy-handed discrimination only further harms an already ailing California business climate.

I am additionally distressed to see lifeline extended to air conditioning. This extension fails to meet the normal test of "paying one's own way". It also subsidizes useage which occurs at annual system peak, when costs are highest. How can the Commission reconcile this with its goals of minimizing utility costs? Of discouraging peak use? Or of maximizing conservation?

III

Today's 12.83% Rate of Return is Too Low.

Adequate return on investment, in layman's terms, is the gas that makes the car go. Low quality return on utility investment means future service to Northern California customers will be characterized by fits and starts. The ratepayer will pay more in the long run in two ways: first, as financial ratings decline, costs of credit rise. Second, as uncertainty is introduced into the company's expansion plans, individual plans for business expansion are made uncertain. Instability and unpredictability in energy-supply chill the state's economy and harm the job market.

PG&E's last offering of common stock occurred in November, 1977. As has become the norm with PUC-regulated utilities, the stock sold for well below book: $23 5/8 per share, versus a book value of $28 7/8. This chronic situation calls for immediate rectification in the form of a higher return and consequent enhanced financial health.

A higher return will also make PG&E's stock more attractive in a period of almost double digit inflation. We must recall that in the late 1960's, when inflation was not nearly the problem it is today, the Commission permitted PG&E to earn an average return on common of 11.5 - 12%. Clearly, the late 1970's call for more than that.

We must also reverse the slide in PG&E's financial rating. Two years ago, its preferred stock was downgraded from Aa to A; its bonds downgraded from "Aa" to "Aa-". This means higher capital costs to a company which must consistently be in the financial market. Yet I see nothing in today's order which will reverse this trend or put PG&E in a better position when it seeks credit.

IV

<u>Today's decision deducts potential Proposition 13 reductions prematurely</u>. By adding $62 million in Proposition 13 reductions to $209 million in ECAC reductions, the Commission is able to publicize this <u>major base rate increase of $229 million</u> ($190 Gas, $39 Electric) as a $41 million rate reduction.

A Proposition 13 deduction is clearly premature for three reasons:

1) The Commission's Order Instituting Investigation on Proposition 13 reductions (OII 19) is still underway. No finding as to the proper amount of tax reductions has been made, $60 million or otherwise.

2) The constitutionality of Proposition 13 is in active court litigation. Oral and written arguments have been made before our California Supreme Court. A decision is pending.

3) Utilities have filed income tax returns for past years which utilize special IRS tax lien provisions. Under the terms of IRS provisions PG&E is precluded from receiving any Proposition 13 tax savings for the year 1978. The tax effects will begin in 1979. The reductions should be timed for 1979 to coincide with the decreases. This is customary regulatory practice.

V

"Time of Use" Rates Should Not be Imposed on California Agriculture

This is a hair-brained concept which shows ignorance of controlling factors for farm irrigation: the crops, the soil, and the weather. These require California farmers to operate arount the clock. Forced "time of use" rates for agriculture would greatly harm our state's number one industry. Mandatory "time of use" rates for agriculture is one camel's nose that should not be allowed under the tent.

San Francisco, California
September 11, 1978

William Symons, Jr.
WILLIAM SYMONS, JR
Commissioner

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COMMISSIONER VERNON L. STURGEON, Concurring

I had hoped that this Commission today would continue taking forward steps in utility regulation, this time by allowing an appropriate return on stockholder equity. The Commission has taken some positive and innovative regulatory steps in the last two or three months that I heartily endorse. Today we took one step sidewise. An allowance of 12.83% is simply not enough, in my judgement, to attract new investors to PGandE stock.

In every case that this Commission issues wherein rate of return is discussed, a long litany of considered items is recited. At the end of this regulatory smog the Commission always announces its continued belief that return on equity is a matter of informed judgement. And so it should be. What seems to get lost in this Commission's consideration of equity allowance, is the fact that the money marketplace in which PGandE and other California utilities must compete for capital is indeed a free marketplace. Investors have a multitude of choices; for example, they can deal in land, commodities, industrial stocks, municipal bonds, utility stocks and bonds, or anything else that appeals to them in or out of the securities market. Investors must be attracted by some prospect of gain. Investors can't be forced to invest. It is the duty of this Commission to set a return at a level which will attract investors.

PGandE faces an immense future financing burden and will need much new investment. This is a burden which we approve. The construction that faces PGandE is a function of the fact that

California is a great state and its economy is a powerful machine and the needs of PGandE's customers absolutely must be met. PGandE simply cannot raise the quantities of capital it will need, at a decent price, if this Commission continues to establish an equity return that investors find unappealing. It means that when PGandE does succeed in attracting an investor, the ratepayers of California will be forced to pay a higher price for the rent of that money than would be the case with an adequate return allowance. A low return on equity is shortsighted thinking that penalizes future ratepayers. 12.83% is too low today.

What did PGandE ask for? 15%. Our Staff, low as always, recommended 12.77%. Recommendations of other parties to the case ranged from 12% to almost 16%. The 12.83% allowed is simply a regurgitation of the PGandE existing equity allowance as if nothing had happened in the world since their last rate case.

If California means business, California must have regulatory decisions that reflect the drives and aspirations of its people. Timidity didn't build California. People who could take the long view built this state. A few more are needed here today. This Commission should recognize that a slightly higher equity allowance today will mean lower financing costs for years to come. Believing that, California regulators must be strong enough to act accordingly. 13% or more has been recognized as appropriate equity level for energy utilities in at least thirty states. Alabama has. Arizona has. Arkansas has. Colorado has. Connecticut has. And on and on and on, including New York, Pennsylvania, Illinois, Massachusetts, Michigan, Ohio, Texas, Wisconsin, etc., etc. California energy utilities deserve at least as much. Investors demand as much.

I have one additional comment to make on today's order. The discussion on page 94 and in Finding 20 regarding time-of-use rates for agricultural pumping ignores the capabilities and economic practices of the real world of agriculture. As a matter of fact, agricultural irrigation pumping systems attain the highest efficiency when operating around the clock. Such operation minimizes waste of both water and energy. Therefore, adjusting the use of agricultural pumps to take advantage of time-of-use rates will not only increase waste, but will require monumental expenditures for additional wells, pumps and distribution systems. Any incentive or disincentive that were provided would be meaningless as far as conservation or peak-load capacity is concerned.

San Francisco, California
September 6, 1978

Vernon L. Sturgeon
VERNON L. STURGEON
Commissioner