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ORIGINAL

Decision 93628 OCT 20 1981

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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| Application of PACIFIC GAS and ELECTRIC COMPANY for authority to revise its gas rates and tariffs effective July 1, 1981, under the Gas Adjustment Clause. (Gas) | Application 60609 (Filed June 1, 1981) |
| Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to increase its electric rates and charges effective August 1, 1981, to establish an annual energy rate and to make certain other rate changes in accordance with the energy cost adjustment clause as modified by Decision No. 92496. (Electric) | Application 60616 (Filed June 2, 1981) |

(See Appendix A for appearances.)

## INTERIM OPINION

In this application Pacific Gas and Electric Company (PG&E) seeks permission to increase its Electric Department revenues by $325.7 million for a four-month period. The increase is requested to allow the company to recover its electric energy fuel and purchased power costs, to collect the costs included in a newly established Annual Energy Rate (AER), and to make up the large undercollection in its Energy Cost Balance Account (ECBA) in four months. In addition to the revenue increases PG&E requests a finding that its fuel practices during the review period were reasonable.

A prehearing conference was held on July 2, 1981, and duly noticed public hearings were held before Administrative Law Judge Kenneth K Henderson on nine days in August. The matter was submitted upon the filing of briefs on September 2, 1981.

Summary

This decision grants PG&E the $325.7 million revenue increase in two parts: $36.6 million is associated with the AER instead of the requested $45.1 million; and approximately $289 million is associated with the ECAC instead of the requested amount of $280 million. This results in an AER of .00257 $/kWh and an average ECAC rate of .05406 $/kWh. Revenue increase is spread among the customer classes on an equal cents per kilowatt-hour basis. The percentage increases for various customer classes regarding effective rates are shown in the table below.

| Class | Increase Amount (000) | Increase Percent |
|---|---|---|
| Residential | | |
| Lifeline | $ 48,948 | 30.0 |
| Nonlifeline | 58,631 | 27.4 |
| Total Residential | 107,579 | 28.5 |
| Small Light and Power | 27,886 | 23.3 |
| Medium Light and Power | 78,259 | 26.6 |
| Large Light and Power | 81,361 | 29.3 |
| Public Authority | 2,039 | 22.3 |
| Agricultural | 24,149 | 27.0 |
| Street Lighting | 2,244 | 16.3 |
| Railway | 1,387 | 31.6 |
| Interdepartmental | 840 | 27.2 |
| Total Jurisdictional | $325,744 | 27.4 |

Procedural Matters

Application (A.) 60609 was filed by PG&E to increase its Gas Department revenues under its Gas Adjustment Clause (GAC). After A.60609 was filed, we issued Decision (D.) 93198 which changed PG&E's GAC revision dates. PG&E has therefore moved that A.60609 be dismissed. The motion is granted.

On June 9, 1981 PG&E filed a petition requesting interim authority to increase rates immediately. Because of the timeliness of this decision and because the balancing account was stable, the petition is moot and is denied.

One last procedural matter that requires resolution is Toward Utility Rate Normalization's (TURN) request for finding of eligibility for compensation under Article 18.5 of the Commission's Rules of Practice and Procedure (Rules). Comments supporting the request were filed by both staff and PG&E. We rule that TURN's participation in this hearing would be a significant financial hardship except for the ability to receive compensation under the Commission's Rules. We find that TURN is eligible for compensation under Rule 76.05. Whether compensation will be paid and, if so, the amount, will be determined as provided by Rules 76.06 and 76.07.

Because this is PG&E's first ECAC proceeding involving a reasonableness review, some general comments are appropriate.

Our most important and distressing observation is that there continues to be a large undercollection problem resulting in unacceptably high balances in the ECBA. It remains our policy that the balancing account should be as low as possible, while at the same time acknowledging the desirable goal of rate stability. At the request of the administrative law judge, PG&E introduced two exhibits in this proceeding analyzing the need for such large ECAC rate increases as this present one. The analysis is not straightforward because there are several independent variables which are changing concurrently, i.e., sales, energy mix, fuel prices, and regulatory lag. Certain problems, however, are clarified.

For PG&E, a major problem in causing large over/under-collections is energy mix. PG&E's generation mix varies widely in cost. The mix ranges from extremely low-cost hydro to very expensive fuel oil generation. Any reduction from normal in the availability of hydro or other low-cost purchased power results in increased generation by fuel oil. With even small reductions in the amount of hydro availability, the very large price difference between hydro and fuel oil results in a very large total cost difference.

There also seems to be a major procedural problem associated with the large undercollection problem. This is well-illustrated by facts surrounding this proceeding. This application was filed on June 2, 1981, with an intended rate revision date of August 1, 1981. The hearings, however, were not held until August 2, 1981 and the matter was only submitted on September 2, 1981 with the decision being rendered today. There will have been a delay of about 90 days between the intended revision date and the date the rates are allowed to go into effect.

There is an additional aspect to this procedural problem which relates to updated information. We have stated often before that we desire to have the most up-to-date information available to assist us in rendering a decision. In this case, PG&E did, indeed, provide the desired information. However, PG&E did not amend its application to take this new information into account. It seems most reasonable to us that when hearings on an application are not held, in an ECAC proceeding, until after the intended revision date, the utility should amend its application to reflect this new information. It can be easily seen that the problem of regulatory lag together with the wide swings in energy mix is a lethal combination leading to the large balancing account balances we have today. We intend to make every effort to solve these problems, and we are sure that the utility will also be anxious to help us.

## I. Annual Energy Rate

In order to arrive at a decision on the total revenue requirement associated with this application, it is first necessary to calculate the AER and its revenue requirement.

### A. Introduction

The purpose of the AER is to recover in rates the estimated costs forecast for the 12-month period beginning August 1, 1981 associated with the following:

1. Fuel oil inventory in rate base;
2. Estimated expense for facilities charges and underlift payments;
3. Gains and losses on the sale of fuel oil; and
4. 2% of the energy costs included in ECAC.

The AER is intended to remain in effect for the 12-month period or until such time as it is superseded by the next such AER.

In addition to the four primary determinations shown above, which are necessary to calculate the AER, various other general issues were raised in this proceeding as follows:

1. Should geothermal and purchased power be included in the 2% factor?
2. Should ad valorem taxes be included in the AER?
3. Should underlifts, facilities charges, and losses on the sale of fuel oil be deferred from AER treatment for one additional year?
4. Should base rates be adjusted to reflect the removal of the fuel oil inventory component of rate base from base rates?
5. Should the AER be changed to reflect a new rate of return granted in an interim general rate increase proceeding?

B. Preliminary Issues

The issue of the treatment of ad valorem taxes is resolved in our Southern California Edison Company (Edison) decision issued today. In that decision, we found that ad valorem taxes are not a direct financing cost. Therefore, ad valorem taxes should remain in rate base and not be included in the AER. Also, for the reasons set forth in the same decision we found that the AER should be changed to reflect any change in the allowable rate of return which the Commission might adopt after the adoption of the AER.

C. Sales and Energy Mix

In its original application, and in the updated information provided by PG&E, the company projected sales of 19,010 gWh for the four-month ECAC period and sales of 54,248 gWh for the one-year AER period. Staff, on the other hand, projected sales of 19,539 gWh for the four-month period and 55,919 gWh for the AER. During the hearing, by statement of counsel, the company accepted the sales figures of the staff. The staff's estimates are based on the result of more recent assumptions regarding the performance of the economy, slightly different econometric models, and the incorporation of five months of recorded data in the staff's projection rather than three months of recorded data in the utility's forecast. The staff has accepted the company's energy mix. No other parties questioned these figures. We will therefore adopt the staff's sales figures for this proceeding.

D. Fuel Oil Inventory Cost Factor

During the hearing, considerable time was spent on the allowable volume of fuel oil in inventory. PG&E proposes an annual average of 9.356 million barrels. Staff supports 6.75 million barrels. TURN in its brief suggested a new procedure which would include the carrying costs of the staff's suggested volumes in the AER and the carrying costs on the excess volumes up to the PG&E suggested volumes in the ECAC. The reasonableness of the excess volumes would be subject to review in the annual ECAC reasonableness proceeding. The TURN procedure seems to have potential merit but was not raised during the hearing and is too complex for us to adopt without full consideration by all parties.

The staff argued that the Commission allowed 6.75 million barrels in PG&E's last general rate case based on a 90-day fuel burn and that therefore the same figure is reasonable for this proceeding. Staff argues that since PG&E concluded in February 1981 that 13.5 million barrels of oil in inventory constituted a burden, PG&E's proposed maximum of 13.25 million barrels for the four-month period beginning August 1 must likewise constitute a burden. Staff also cites increased gas availability, the lack of possible oil supply problems, the possible addition of Diablo Canyon, PG&E's efforts to reduce oil consumption, and its oil contract renegotiations as further support of its estimate. Staff essentially relies on a normal rather than a recorded beginning test year oil inventory, based on PG&E's actual needs.

CMA also takes issue with PG&E's estimate of average oil in inventory but did not propose a different level.

PG&E, on the other hand, undertakes a rigorous analysis that takes into account economic, as well as operational considerations. In determining operational needs, PG&E strongly believes that it must have at least 10 million barrels of oil in inventory by December 1, and must never foreseeably fall below 5 million barrels at any time in order to ensure reliability of service. PG&E maintains that 11.9 million barrels are required for December and 8.5 million barrels for January 1982 in order to maintain the 5 million barrel minimum at the end of each of these months.

PG&E's economic analysis of fuel oil inventory takes into account its contractual obligations, and the limited flexibility to underlift or resell excess oil. This analysis results in holding oil in inventory at the summer level of 13 million barrels for use in the upcoming winter.

We point out that PG&E regards fuel oil inventory as one element of its total fuels management. Fuel oil inventory is a tool to enhance fuel oil supply flexibility. We agree with the PG&E's economic and operational analysis of reasonable volumes of fuel oil in inventory but also believe that staff's reliance on a normative test year is appropriate. The following table illustrates the position of PG&E, staff, and the volume that we will adopt.

| 1981 | End of Month Inventory Average Million Barrels PG&E[a] | Staff[b] | Adopted Volumes |
|---|---|---|---|
| Half of July | 6.66 | 3.25 | 4.563 |
| August | 13.247 | 6.5 | 10.206 |
| September | 13.107 | 6.5 | 11.727 |
| October | 13.248 | 6.5 | 13.248 |
| November | 11.878 | 10. | 11.878 |
| December | 8.454 | 6.5 | 8.454 |
| 1982 | | | |
| January | 5.531 | 6.5 | 5.531 |
| February | 6.025 | 6.5 | 6.025 |
| March | 6.649 | 6.5 | 6.649 |
| April | 7.193 | 6.5 | 7.193 |
| May | 7.732 | 6.5 | 7.732 |
| June | 8.201 | 6.5 | 8.201 |
| Half of July | 4.343 | 3.25 | 4.343 |
| Total | 112.268 | 81.499 | 105.530 |
| Annual Average | 9.356 | 6.751 | 8.794 |

(a) Obtained from Ex. 3, p. 3-5.

(b) Staff witness Ghazzagh explained that the staff annual average could be conceptually derived by assigning these averages to each month (Tr. 573).

As can be seen in the table, we have adopted as reasonable a beginning inventory of 8.685 million barrels and then allowed an orderly increase of inventory to 13.248 million barrels, which PG&E projects it will require beginning November 1, 1981. The subsequent monthly volumes are as projected by the company.

Although we think that the 8.794-million-barrel annual average is fair, we are not satisfied with the analysis presented by either PG&E or the staff. In D.92496 we directed PG&E to engage an independent consultant to develop a procedural refinement that would better divide the burden associated with excess fuel oil between the ratepayers and shareholders. The consultant has been engaged and a draft report completed. We are optimistic that a final report will be filed before the next AER proceeding.

Our adoption of the 8.794-million-barrel volume leads to the revenue requirement calculation shown in the following table.

## Oil Inventory Revenue Requirement for AER

| Line | | |
|---|---|---|
| 1 | Annual Average | 8,794 (Mbbl) |
| 2 | Weighted Average July 31, 1981 Oil Inventory Price | $37.07 Per Barrel |
| | | Dollars in Thousands |
| 3 | Total Inventory (Line 1 x 2) | $325,993 |
| 4 | Allocation to CPUC Jurisdiction (a) | 312,204 |
| 5 | Ad Valorem Taxes | 0 |
| 6 | Return and Income Taxes (b) | 53,575 |
| 7 | Revenue Requirement (Line 5 + Line 6) | 53,575 |
| 8 | Franchise Fees and Uncollectible Accounts Expense (c) | 418 |
| 9 | Adjusted Revenue Requirement | $ 53,993 |

(a) Line 3 x .9577.

(b) Based on 10.34% rate of return and net-to-gross multiplier of 1.6596.

(c) Line 7 x 0.0781.

E. Facilities Charges, Underlifts, and Losses on the Sale of Fuel Oil

The next elements of the AER to be calculated are the facilities charges, underlift payments, and loss/gain on the sale of fuel oil. Fuel oil supply flexibility is a valuable element in a fuels management strategy which carries with it certain costs. The costs of this flexibility are usually incurred as either:

1. Facilities charges.
2. Underlift payments.
3. Losses on the sale of oil.
4. Higher price for the oil.

PG&E is currently renegotiating its contract with its major supplier of fuel oil. The renegotiated contract will have a major impact on the level of charges for these items in the test year. As a result, any estimates are extremely tenuous at best. PG&E, therefore, suggests that these three items be included in the ECAC (balancing account treatment) rather than in the AER for an additional year. The staff is in basic agreement with PG&E.

The California Manufacturers Association (CMA) and TURN argue that our intention expressed in D.92496 was clear and unequivocal that these items would no longer be included in ECAC. We agree. Our intention in D.92496 was to create incentives for proper fuels management by the introduction of the possibility of rewards and losses. We see no sufficient reason to change our decision at this time. Accordingly, these items will be included in the AER (which is an estimated forecast not subject to recovery in the ECAC balancing account).

PG&E has provided estimates of $39,372,000 in facilities charges, $9,768,000 in underlift payments, and $13,149,000 in losses on the sale of fuel oil. The estimate of $39.4 million for facilities charges is based on PG&E's latest offer and reflects an outcome of the negotiations favorable to PG&E. TURN argues that the estimate is not sufficiently supported for us to adopt. TURN, however, offers no alternative. We believe that PG&E's estimate for facilities charges is reasonable in that it represents what PG&E considers a favorable deal to them if accepted by Chevron.

PG&E's estimates for underlift payments and losses on the sale of fuel oil are based on recent record period expenses. There was no further evidence supporting these estimates for the forecast year.

California Farm Bureau Federation (Farm Bureau) correctly points out that facilities charges, underlift payments, and sale losses are, in a sense, substitutes for each other. Facilities charges are designed to cover the investment made by the oil supplier in facilities specially constructed to meet the utility's needs. These charges are much like demand charges. Underlift payments are payments made to the oil supplier for oil not taken, and are also designed to recover the investment in facilities necessary to supply the utility. As such, facilities charges may substitute in whole or in part for underlift payments in that both are designed to recover costs associated with maintaining the supplier's capacity to serve. Sales of oil from inventory may also be viewed as a substitute for underlifting fuel or paying facilities charges. Farm Bureau and CMA argue, and we agree, that we cannot accept PG&E's estimate for newly incurred facilities charges and at the same time accept the fact that underlift charges and sale losses will continue to be incurred. The figures that we adopt as reasonable are as follows:

| | | |
|---|---|---|
| 1. | Facilities Charges | $39,372,000 |
| 2. | Underlift Payments | 0 |
| 3. | Losses on the Sale of Oil | 0 |

F. <u>2% of Fuel Expense</u>

Two primary issues regarding the calculation of fuel expense for the test year remain, once the sales figure and jurisdictional factors have been adopted. These two issues are (1) whether geothermal and purchased power should be included in the calculation, and (2) the forecast price of natural gas.

The issue of the inclusion of geothermal and purchased power is raised by a minor ambiguity in D.92496. PG&E reads the decision so that only fossil fuel expenses should be included in the 2% figure. The staff, on the other hand, argues that geothermal and purchased power should be included. The staff has correctly interpreted our intention regarding inclusion of the item. All ECAC energy prices are fuel-related and subjected to management negotiation. The incentive feature of the 2% factor should also apply to geothermal and purchased energy. Our recent decisions regarding Sierra Pacific and Edison are consistent on this issue.

The other issue is the forecast prices to be adopted for the test year. The staff agrees with PG&E's estimated energy prices. Both TURN and CMA take exception to the forecast average natural gas price of $5.6072 per million Btu.

PG&E's estimate assumes that its price for natural gas will increase almost 50% on July 1, 1982. This projection is based on the assumption that the Commission will set the G-55 rate at the alternate fuel price projected by PG&E. TURN correctly points out that the G-55 gas rate is set in reference to a constructive market price of oil. That the oil market is currently "soft" is common knowledge. We feel that a much more conservative estimate is warranted. We project that the G-55 gas rate will increase no more than 30% during the forecast year. We will therefore adopt $4.80 per million Btu as a reasonable average price of natural gas over the forecast test year. The table below illustrates the calculation of the 2% fuel expense factor in accordance with our resolution of the estimated price of natural gas and inclusion of geothermal and purchased power.

2% of Estimated Fuel Expenses for AER

| Line | | Estimated Quantity(a) | Estimated Price(b) | Dollars in Thousands |
|---|---|---|---|---|
| 1 | Gas | 258,550 | 4.80 | $1,241,040 |
| 2 | Oil-Residual | 167,801 | 5.8334 | 978,850 |
| 3 | Oil-Distillate | 2,166 | 6.8361 | 14,807 |
| 4 | Geothermal | 6,302.85 | 27.76 | 174,967 |
| 5 | Purchased Power | 9,006.98 | 22.50 | 202,657 |
| 6 | | | | 2,612,321 |
| 7 | Allocation to CPUC Jurisdictional (Ln 6 x .9577) | | | 2,501,820 |
| 8 | 2% of Fuel Expense (Ln 7 x .02) | | | 50,036 |
| 9 | Franchise Fees and Uncollectible Accounts (Ln 8 x .00781) | | | 391 |
| 10 | Revenue Requirement | | | $ 50,427 |

(a) In millions of Btu.
(b) In dollars per million Btu.

G. Adjustment to Base Rates

The last element requiring calculation to allow a determination of the revenue requirement associated with the AER is the adjustment to base rates as provided by D.92496. The only issues raised in PG&E's calculations are differences regarding sales volumes and ad valorem taxes which we have previously resolved. The following table illustrates our adopted figures.

Calculation of Revenue Requirements Associated with Fuel Oil in Inventory Underlying Present Base Rates Adopted in D. 92656

| Line | | Dollars in Thousands (a) |
|---|---|---|
| 1 | Fuel Oil Inventory Component of Adopted Rate Base | $235,812 |
| 2 | CPUC Jurisdictional Fuel Oil Inventory Component of Adopted Rate Base (b) | 226,097 |
| | Revenue Requirement | |
| 3 | Ad Valorem Taxes | 0 |
| 4 | Return and Income Taxes (c) | 38,799 |
| 5 | Total Revenue Requirement | 38,799 |
| 6 | Franchise Fees and Uncollectible Accounts (d) | 303 |
| 7 | Adjusted Revenue Requirement | 39,102 |
| 8 | Total Applicable CPUC Jurisdictional Sales gWh | 56,103 |
| 9 | Base Rate Component Associated with Fuel Oil in Inventory (e) | .0697 ¢/kWh |
| 10 | Revenue from Test Year Sales Associated Fuel Oil in Inventory (f) | $ 38,976 |

(a) Unless otherwise noted.
(b) Line 1 x 0.9588.
(c) Based on 10.34% rate of return and net-to-gross multiplier of 1.6596.
(d) Line 5 x 0.00781.
(e) Line 7 ÷ Line 8.
(f) Line 9 x applicable sales of 55919 gWh.

H. Summary of Annual Energy Rate and Revenue Requirement for Test Year Beginning August 1, 1981

The figures adopted in Sections D-G above are used to construct the table below, which is a summary of the AER and associated revenue requirement. The table shows that present base rates should be decreased by .0007 $/kWh to reflect the removal of cost associated with fuel oil in inventory. The new AER is .00257 $/kWh. The four-month revenue requirement is developed on line 9 of the table below. This figure becomes important when we later develop the ECAC revenue requirement.

Summary of Annual Energy Rate Revenue Requirement
Test Year Beginning August 1, 1981

| Line | | PG&E $M | Adopted $M |
|---|---|---|---|
| 1 | Revenue Requirement Associated Fuel Oil in Inventory | 61,469 | 53,993 |
| 2 | Facilities Charges | 39,372 | 39,372 |
| 3 | Underlift Payments | 9,768 | 0 |
| 4 | Two Percent of Estimated Fuel Expense | 45,317 | 50,427 |
| 5 | Loss on Sales of Fuel Oil | 13,149 | 0 |
| 6 | Total Revenue Requirement | 169,075 | 143,792 |
| 7 | Less: Revenue Associated with the Fuel Oil Inventory Volume and Average Oil Price in Present Base Rates | (40,144) | (38,976) |
| 8 | Net Increase in Revenue Requirement | 128,931 | 104,816 |
| 9 | 4-month Increase in Revenue Req. | 45,181 (1) | 36,624 (2) |
| 10 | Annual Sales gWh | 54,248 | 55,919 |
| 11 | Annual Energy Rate (L.6 ÷ L.9) | .00311$/kWh | .00257$/kWh |
| 12 | Decrease of Base Rates | .00074$/kWh | .00070$/kWh (3) |

(Red Figure)

(1) 128,931 ÷ 54,248 x 19,010 = 45,181

(2) 104,816 ÷ 55,919 x 19,539 = 36,624

(3) .000697 rounded

## II. Energy Cost Adjustment Clause Rate and Revenue Requirement

The calculation of the ECAC rate and revenue requirement in this proceeding is most interesting. During the hearings on this matter there were virtually no issues raised regarding its calculation. The potential issues that are often raised in these proceedings concern the following:

1. Sales volumes.
2. Energy mix.
3. Energy prices.
4. Balancing Account Balance.
5. Amortization period.
6. Use of updated information regarding Items 1, 2, 3, and 4 above.

In this proceeding the staff accepted the company's estimates regarding energy mix, balancing account balance, and amortization period. Also, the staff accepted the company's updated estimate of prices. No other parties disagreed.

The staff did, however, offer an adjustment to the balancing account. The staff recommended that $208,000 be removed from the balancing account because that represented a portion of the balance in the PG&E tax cost adjustment clause balance which was transferred into PG&E's ECBA under Resolution E-1910. The issue revolves around D.90000 issued February 27, 1979. However, the company argues, and the staff acknowledges, that the debit entry for lost streetlighting revenue was consistent with PG&E's ECAC tariff as approved by this Commission. We will, therefore, not adopt the adjustment recommended by the staff.

The staff provided a different sales figure with which the company did not disagree. As discussed in the AER section of this opinion, we have adopted the staff's sales volumes and PG&E's energy mix and updated energy price estimates for the four-month ECAC period. The staff did not take a definitive position with regard to the updated balancing account balance.

With these major agreements among the parties the calculation of the ECAC would seem to be rather noncontroversial. The following table illustrates, however, rather significant differences.

Comparison Calculation of ECAC Rate and Revenue Requirement

| Line | | PG&E Original | PG&E Update ($M) | Staff | Adopted |
|---|---|---|---|---|---|
| | Gas | | | | |
| 1 | Quantity | 92,661 | 92,661 | 93,378 | 93,378 |
| 2 | Price | $ 4.2815 | 4.2938 | 4.2938 | 4.2938 |
| 3 | Expense | $396,728 | 397,868 | 400,946 | 400,946 |
| | Residual Oil | | | | |
| 4 | Quantity | 52,341 | 52,341 | 58,659 | 58,659 |
| 5 | Price | $ 5.6776 | 5.6776 | 5.6776 | 5.6776 |
| 6 | Expense | $297,173 | 297,173 | 333,045 | 333,045 |
| | Distillate Oil | | | | |
| 7 | Quantity | 700 | 700 | 701 | 701 |
| 8 | Price | $ 6.6029 | 6.6029 | 6.6029 | 6.6029 |
| 9 | Expense | $ 4,622 | 4,622 | 4,628 | 4,628 |
| | Geothermal | | | | |
| 10 | Quantity | 1,902 | 1,902 | 1,902 | 1,902 |
| 11 | Price | $ 27.76 | 27.76 | 27.76 | 27.76 |
| 12 | Expense | $ 52,800 | 52,800 | 52,800 | 52,800 |
| | Purchased Power | | | | |
| 13 | Quantity | 3,881 | 3,881 | 4,289 | 4,289 |
| 14 | Price | $ 21.66 | 21.66 | 21.60 | 21.60 |
| 15 | Expense | $ 84,062 | 84,062 | 92,646 | 92,646 |
| 16 | Oil Inventory Adj. | 249 | 249 | 249 | 249 |
| 17 | 2% Energy Cost | (13,970) | (13,993) | (17,681) | (17,681) |
| 18 | DWR | (2,231) | (2,231) | (2,783) | (2,783) |
| 19 | Total Expense | $819,433 | 820,550 | 863,850 | 863,850 |
| | Allocation to | | | | |
| 20 | CPUC Jurisdiction | 782,722 | 783,789 | 827,568 (a) | 827,568 (a) |
| 21 | ECAC Balance | 207,459 | 245,098 | 207,251 | 245,098 |
| 22 | Total | 990,181 | 1,028,887 | 1,034,819 | 1,072,666 |
| 23 | Franchise & Uncollectibles (b) | 7,733 | 8,036 | 8,082 | 8,374 |
| 24 | ECAC Revenue Requirement | 997,914 | 1,036,923 | 1,042,901 | 1,081,044 |
| 25 | Revenue at Present Rates | 715,809 | 712,719 | 767,257 | 767,257 |
| 26 | Revenue Increase | 282,105 | 324,204 | 275,644 | 313,787 |

(Red Figure)

(a) Ln 19 x .9580

(b) Ln 22 x .00781

The major difference between the PG&E's original and updated calculation is the result of an updated balancing account estimate shown on Line 21 ($207 vs $245 million). The major differences between the staff's estimates and the company's updated estimates lie with the total energy cost (Line 19) ($820 vs $863 million), and balancing account balance (Line 21), ($245 vs $207 million). Although these two differences are each large, they are also offsetting. The other significant difference shown in these two columns is the estimate of revenue earned at present rates, (Line 25). The difference ($54.5 million) is the result of the staff's higher sales estimates and a different sales profile.

The last column of the table shows the results of our adopted estimates. We have adopted the staff's higher sales volumes and prices resulting in a major difference with the company. (Line 19). Also, we have used the updated balancing account figure of $245 million (Line 21). Our adopted estimates result in an ECAC revenue requirement for four months of $313.8 million.

The ECAC calculation brings us to our major dilemma in this case, namely, the reconciliation of the total (ECAC plus AER) requested revenue increase of $325.7 million and our calculated requirement of $350.42 million.

The company has provided updated information which was not seriously contested and has requested that we be aware of the new information when we consider any adjustments offered by the staff or other parties. Most importantly, however, PG&E, for whatever reasons, did not choose to amend its application to reflect the updated information. The following table shows the results.

Difference Between Revenue Requested and Revenue Required
($M)

| Line | | PG&E | PG&E Update | Staff | Adopted |
|---|---|---|---|---|---|
| 1 | AER 4-month increase | $ 45.1 | $ 45.1 | $ 19.7 | $ 36.62 |
| 2 | ECAC Revenue increase | 280.6 | 324 | 275.6 | 313.8 |
| 3 | Total | $325.7 | $369 | $295.3 | $349.92 |
| 4 | Total Revenue Requested | $325.7 | $325.7 | $325.7 | $325.7 |
| 5 | Difference (Ln 3 - Ln 4) | 0 | 43.3 | (30.4) | 24.7 |
| 6 | Total ECAC Revenue that can be granted (Ln 4 - Ln 1) | $280.6 | $280.6 | $ 306 | $289.076 |

Our dilemma then is that by using the estimates that we believe are most realistic and accurate we are compelled to grant an ECAC revenue increase which will result in a $24.7 million under-collection. The ECAC revenue requirement and rate which we grant in this application are developed below in the following table.

Adopted ECAC Rate

| | | | |
|---|---|---|---|
| 1. | Present ECAC Rate $/kWh | = | .039268 |
| 2. | ECAC Revenue Increase | = | 289,076 |
| 3. | Sales MM kWh | = | 19539 |
| 4. | ECAC Rate increase $/kWh (Ln 2 ÷ Ln 3 | = | .01479 |
| 5. | Present ECAC Rate | = | .039268 |
| 6. | New ECAC RAte $/kWh | = | .05406 |

III. Reasonableness Review

In D.92496 and D.93198 we ordered an annual review of the reasonableness of recorded energy costs recovered through the ECAC and GAC procedures. The instant August 1 proceeding is the annual review proceeding for PG&E.

PG&E presented lengthy reports covering the operations of both the Gas and Electric Departments during the review period. Each report analyzed past decisions and showed that at the time the decisions were made they were reasonable in the context of the prevailing conditions and available information.

The staff presented three witnesses who agreed that the practices of PG&E were reasonable during the review period.

TURN was the only other party participating in this aspect of the proceeding. Although TURN provided no witnesses concerning reasonableness, it extensively cross-examined both PG&E's witnesses and the staff witnesses. The effect of the cross-examination was to show that the conclusions of the staff witnesses representing the Electric Branch and the Revenue Requirements Division lacked foundation.

TURN argues in its brief that PG&E acted unreasonably in failing to (1) terminate a field oil contract with Union Oil in September 1979, instead of in December 1981, and (2) take advantage of available economy energy during July 20 through 22, 1980.

PG&E counters that it acted reasonably in not terminating the Union Oil contract in September of 1979 because during most of that year oil supply was limited due to the Iranian crisis. PG&E also shows that its failure to purchase economy energy from Edison during the period in 1980 was the result of a mistake on the part of its operating personnel and that a new system has been installed to prevent such mistakes in the future. We agree with PG&E that such mistakes cannot be characterized as imprudent management.

## IV. Revenue Allocation and Rate Design

In this proceeding, we are presented with two radically different revenue allocation methodologies. The most familiar of the two is the equal cents per kilowatt-hour method which we have consistently used in allocating ECAC revenues for PG&E. The newer method was presented by TURN. This method is a further refinement of the method presented by PG&E in A.60225 (ECAC) and TURN in A.60153 (general rate case).

TURN's new refinement is the introduction of the concept of the "class marginal rate" (CMR) which is a weighted average of the marginal rates within a class. The TURN proposal is that the CMR should bear the same relationship to the class marginal costs among all customer classes. Previous marginal cost proposals embodied the concept that the class average rate should bear some relationship to the class marginal costs. The rationale for the new concept is that rates set in accord with the concept will result in greater efficiency and energy conservation. These results obtain because marginal rates are more price sensitive than average rates or total bill size in determining individual customer behavior. In the residential class, the class marginal rate is much higher than the class average rate because of rate inversion; in all other classes, the class marginal rate and class average rate are equal. If class marginal rates are set in the same relationship to marginal costs for all customer classes, then there would be a major shift of the revenue burden out of the residential class.

TURN's proposal met with strong opposition from CMA, the Board of Trustees of the Leland Stanford Junior University (Stanford), and the Farm Bureau, as a matter of procedure as well as substance.

These parties strenously objected to the litigation of rate design issues in an ECAC proceeding, maintaining that such issues are more appropriately addressed in a general rate proceeding. They contend that because rate design issues require considerable time and commitment of resources, a thorough analysis of these issues necessarily delays an expeditious decision required for an offset proceeding.

TURN countered that the Commission, by D.93196 in PG&E's last ECAC proceeding, specifically encouraged parties to introduce in an ECAC proceeding different methods of rate spread other than the equal ¢/kWh method. TURN also argued that an ECAC proceeding is an appropriate forum to consider rate design alternatives in light of the substantial increase sought by PG&E.

CMA, Stanford, and the Farm Bureau also perceive several substantive defects in TURN's proposal. They argue, among other things, that the TURN methodology improperly weighs customer usage in the residential tiers, fails to consider marginal customer and distribution costs, and is insensitive to changes in marginal costs. All three contend that the methodology inequitably favors residential customers over large users by shifting a substantial portion of the revenue burden from the residential to large users than would otherwise result.

In resolving the procedural issue, we agree with TURN that in D.93196 we invited parties to address rate design methodologies employing marginal cost concepts in an ECAC proceeding.1/ Unfortunately, at that time, we did not fully recognize the practical dilemma which we inadvertently created. The dilemma is that the need to provide ample hearing time to fully explore new and complex rate design concepts

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1/ In fact, PG&E also introduced a rate design proposal to time-differentiate ECAC rates.

conflicts with the need to provide timely rate relief in an offset proceeding in order to ensure rate stability. We now believe that a general rate proceeding is the most appropriate forum for developing rate design proposals. In those proceedings, sufficient time is afforded to allow all interested parties the opportunity to thoroughly examine existing and new rate design proposals. Rate cases also give the Commission ample opportunity to carefully consider and ultimately adopt rate design policy. Henceforth, we will therefore address rate design issues in general rate cases only. We point out that this policy is consistent with our decision to not treat rate design issues in offset proceedings for our southern California utilities.

In this proceeding, however, we believe that TURN properly accepted our "invitation" in D.93196 to introduce a rate design proposal based on marginal cost concepts. We note that PG&E's general rate case has recently been submitted and is scheduled for decision at the end of this year. In PG&E's general rate case numerous issues were presented which could have a significant effect on TURN's proposal, i.e., use of marginal cost in ECAC proceedings, a different usage blocking in the residential class, and issues regarding the customer charge. We, therefore, feel that a decision on TURN's proposal would be premature at this time.

We are also concerned that TURN's proposal did not receive sufficient attention from those parties which consistently participate in our general rate cases. We are therefore reluctant to act on the proposal without thorough analysis and review by all interested parties.

To resolve these difficulties without abandoning TURN's proposal, we have decided to set further hearings in this application for the limited purpose of addressing the rate design issues presented by TURN. These hearings will be set after our decision in PG&E's general rate case, and will provide parties the opportunity to examine TURN's rate design proposal in light of the policies which we adopt in the general rate decision. We especially urge our staff and PG&E to actively participate in these hearings.

Any final action which we may take in this application will be prospective only, and will only affect proceedings subsequent to the issuance of our final order in this case. The question of whether to award TURN PURPA intervenor fees, and if so, how much, is reserved for further hearings. We have already determined eligibility.

With this resolution of the TURN proposal, we will adopt for this proceeding the equal cents per kilowatt hour method of allocating the ECAC revenue increase. The results are shown on the following table.

Revision Date: August 1, 1981
Forecasted Period: Four Months Beginning August 1, 1981

| Item | Millions of kWh | Thousands of Dollars | Rate Per kWh of Sales |
|---|---|---|---|
| Adjustment Increase Applicable to System Sales | 19,539 | $289,076 | .01479 |
| Adjustment Increase Applicable to Nonresidential Sales | 13,223 | 195,568 | .01479 |
| Adjustment Increase Applicable to Lifeline (Tier I) Sales | 3,539 | 40,982 | .01158 |
| Adjustment Increase Applicable to Nonlifeline (Tier II) Residential Sales at 38% above the Tier I Increase | 1,433 | 22,899 | .01598 |
| Adjustment Increase Applicable to Nonlifeline (Tier III) Residential Sales at 38% above the Tier II Increase | 1,344 | 29,635 | .02205 |
| Total Residential Sales | 6,316 | 93,508 | .01479 |

The remaining rate design issue which was raised by PG&E concerns the adoption of time-varying ECAC rates for the time-of-use Schedules A-21, A-22, and A-23.

PG&E proposed time-varying ECAC rates for the time-of-use schedules in order to maintain the relationship of on- and off-peak prices. PG&E argues that as equal increases are applied to the on- and off-peak rates, there is less incentive for a customer to shift load to an off-peak period. Specifically, PG&E states that:

> "With the addition of a uniform ECAC rate to energy prices in all time periods the time of use price signals have been greatly weakened. If the differential were incorporated into the ECAC portion of the effective rate, rather than the base rate portion, the relevant ratio between on-peak and off-peak prices would be maintained in subsequent ECAC proceedings.
>
> "As applied to present rates PG&E's proposal would result in no difference to the customers as far as the total rate is concerned. The only difference as compared with existing procedure is in the portion of the rate that is in base rates and the portion that is in ECAC rates."

As with TURN's proposal Stanford and CMA believe it inappropriate to consider PG&E's proposal in an ECAC proceeding. We have already discussed in connection with the TURN proposal that we would specifically entertain rate design issues in this ECAC proceeding. We therefore find it reasonable to consider PG&E's proposal at this time.

Stanford and CMA also question the rationale for time differentiating ECAC rates. Their basic argument is that an absolute differential is sufficient incentive for a customer to not move from off-peak to on-peak usage. The other substantive argument is that embedded costs underlie the time-of-use rates, in that the cost of producing the energy varies by time-of-use, therefore, there can be a different rate for off-peak/on-peak usage. A cost study would therefore have to be performed in order to alter the off-peak/on-peak differential.

PG&E responded that cost differentials between peak and off-peak rates are only one factor to be considered in establishing a rate design. Conservation and load management considerations are equally important in determining the differentials for these rates.

We concur with PG&E that conservation and load management are as important as cost of service. While we agree that an absolute differential between on and off-peak rates influences on- and off-peak usage, we believe that the magnitude of the differential more likely influences this. We find that a time-varying ECAC procedure will more properly maintain the relationship of off-peak and on-peak rates over time and therefore the magnitude of the incentive to shift to off-peak usage will not decrease.

Findings of Fact

1. By A.60616 PG&E requests authority to make changes in its base rates and ECAC billing factors and to include an AER factor increasing revenues by $325.7 million for a four-month period.

2. The adopted ECAC rates will increase PG&E's electric revenues by $289,076,000 for a four-month period.

3. A four-month period to amortize the balancing account will minimize the undercollection. The balancing account balance of $245,098,000 is a reasonable estimate to use as of August 1, 1981.

4. The staff's sales volumes of 19,539 gWh for a four-month period and 55,919 gWh for the one-year period, each beginning August 1, 1981, are reasonable.

5. No evidence was offered to indicate that PG&E's recorded energy costs for the review period were unreasonable.

6. Ad valorem taxes should not be included in the computation of the AER.

7. Both geothermal and purchased power expenses should be included in the calculation of the AER.

8. 8.794 million barrels of fuel oil in inventory is a reasonable level to be allowed for the test year.

9. Underlifts, facilities charges, and losses on the sale of fuel oil should not be deferred from AER treatment for one year.

10. The facilities charge is a constant charge which should be recovered on a uniform basis.

11. Fuel oil market conditions and inventory levels suggest that PG&E has overestimated the price of fuel oil for the 2% factor. A price of $4.80 per million Btu is a reasonable price to be adopted for the price of natural gas for the test year.

12. The adopted AER rate is .00257 $/kWh.

13. Present base rates should be reduced by a figure of .00070 $/kWh.

14. PG&E has shown an ECAC revenue need greater than requested.

15. ECAC rate increase of .01479 $/kWh is adopted.

16. The development of the AER, ECAC rates, and reduction of base rates as calculated in this decision is reasonable.

17. The AER should be revised whenever the Commission adopts a change in the authorized rate of return.

18. The equal ¢/kWh method is reasonable for spreading the increased revenue requirement among customer classes.

19. There is insufficient basis on this record to adopt a marginal cost-based rate design at this time.

20. Time-varying ECAC rates should be established for the time-of-use Schedules A-21, A-22, and A-23, as proposed by PG&E.

21. The increase in rates and charges authorized by this decision is justified and reasonable.

22. TURN is eligible for compensation under Rule 76.05.

23. Because of the substantial undercollection there is immediate need for rate relief. Therefore, the effective date of this order should be the date of signature.

Conclusion of Law

PG&E should be authorized to establish the revised rates set forth in the following order which are just and reasonable.

## INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is authorized to establish and file with this Commission in conformity with provisions of General Order 96-A, revised tariff schedules of base rates, AER, and ECAC billing factors as shown in Appendix B, and to revise its streetlighting rates accordingly. Also, PG&E is authorized to apply time-varying ECAC factors to the time-of-use Schedules A-21, A-22,

and A-23 in accordance with the proposal of this application. The revised tariff schedule shall become effective not earlier than five days after filing. The revised schedule shall apply only to service rendered on or after the effective date of this order.

2. A.60609 is dismissed.

This order is effective today.

Dated OCT 20 1981, at San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
PRISCILLA C. GREW
Commissioners

I certify that this decision was approved by the above Commissioners today.

Joseph E. Bodovitz

APPENDIX A

LIST OF APPEARANCES

Applicant: Daniel E. Gibson, Attorney at Law, by Bernard Della Santa and Shirley Woo, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Gregg Wheatland, Attorney at Law, for the California Energy Commission; Harry K. Winters, for the University of California; Biddle, Walters & Bukey, by Richard L. Hamilton, Halina Osinski, Attorneys at Law, for Western Mobilehome Association (WMA); Robert Spertus, and Michel Peter Florio, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Brobeck, Phleger & Harrison, by Gordon E. Davis, William H. Booth, and James M. Addams, Attorneys at Law, for California Manufacturers Association; W. Randy Baldschun, for the City of Palo Alto; John Bury, H. R. Barnes, L. R. Cope, S. L. Steinhausen, Carol B. Henningson, Robert M. Loch, Thomas D. Clark, Attorneys at Law, and Margaret E. Thomas, for Southern California Edison Company; Nancy I. Day, for Southern California Gas Company; Henry F. Lippitt, for California Gas Producers Association; Glen J. Sullivan, and Allen R. Crown, Attorneys at Law, for California Farm Bureau Federation; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr, Attorney at Law, for General Motors; William R. Reed, Attorney at Law, for San Diego Gas & Electric Company; and William E. Swanson, Lynda Weisberg, John Schaefer, and Adrian Arima, Attorney at Law, for The Board of Trustees of the Leland Stanford Junior University.

Commission Staff: James S. Rood, Attorney at Law.

# APPENDIX B

| | Present* (A) | Increase* (B) | Adopted* (A)+(B) |
|---|---|---|---|
| A. ECAC Rates | | | |
| Nonresidential | .039268 | .01479 | .05406 |
| Residential | | | |
| Tier-1 | .01781 | .01158 | .02939 |
| Tier-2 | .04322 | .01598 | .0592 |
| Tier-3 | .02205 | .06824 | .09029 |
| B. Base Rates (Residential) | .02250 | (.0007) | .0218 |
| C. Base Rates (Nonresidential) | - | (.0007) | - |
| D. Annual Energy Rate | - | .00257 | .00257 |
| E. Solar Financing Adjustment | .00002 | - | .00002 |
| F. Effective Residential Rates (A + B + D + E) | | | |
| Tier-1 | .04033 | .01345 | .05378 |
| Tier-2 | .06574 | .01785 | .08359 |
| Tier-3 | .09076 | .02392 | .11468 |

(Red Figure)

*Dollars per kWh.