ALJ/BDP/jt *

Decision 87 11 019 NOV 13 1987

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Application of Pacific Gas and Electric Company for Commission order finding that PG&E's gas and electric operations during the reasonableness review period from February 1, 1986, to January 31, 1987, were prudent. (U 39 M)	Application 87-04-005 (Filed April 7, 1987)
Application of Pacific Gas and Electric Company for authority to adjust its electric rates effective August 1, 1987.	Application 87-04-035 (Filed April 21, 1987)

(See Appendix A for appearances.)

INTERIM OPINION

Phase 1

This decision reviews Pacific Gas and Electric Company's (PG&E) electric sales and related fuel and energy costs for the forecast period August 1, 1987 to July 31, 1988. The Commission concludes that PG&E is entitled to electric revenue increases to Energy Cost Adjustment Clause (ECAC), Annual Energy Rate (AER), and Electric Revenue Adjustment Mechanism (ERAM) on an annualized basis of $53.6 million, $3.2 million, and $210.2 million, respectively, for a total of $267.0 million. However, for reasons which are set forth, these increases are deferred and will not be reflected in increased rates at this time.

The $53.6 million amount relates to a 91% portion of fuel and energy related expense increase for the forecast period covered by PG&E's ECAC.

The $3.2 million amount relates to the remaining 9% portion of fuel and energy related expense increase covered by PG&E's AER.

The $210.2 million amount is to offset underrecovery of fixed operation and maintenance costs (excluding fuel) resulting from lower than forecasted sales, as covered by PG&E's ERAM.

<u>Summary</u>

For purposes of PG&E's August 1, 1987 to July 31, 1988 ECAC/AER forecast, this decision decides the contested issues as follows:

I. Nuclear Plant Operations:

A. Rancho Seco will provide zero generation for the forecast period.

B. Diablo Canyon Units 1 and 2 will achieve a 75% operating cycle capacity factor.

II. For AER revenue requirement purposes, the UEG gas rate stipulation, Exhibit 10, should be used to calculate Incremental Energy Rates (IER) in accordance with the methodology in PG&E's Exhibit 3, p. 3, Table 1, Case 2. For Phase 2 IER calculation, parties may adjust Exhibit 10 to reflect the underlying volumetric change.

III. Large thermal Qualifying Facility (QF) Projects Nos. 15, 16, 24, and 25 will provide zero generation during the forecast period.

IV. A. QF energy delivered under Energy Payment Option 3 (EPO 3) of Standard Offer 4 (SO 4) should be treated as receiving fixed payments for purposes of this proceeding.

B. A 50/50% split (fixed versus variable) should be used to allocate energy delivered by QFs less than 1 megawatt (MW) in size for purposes of this proceeding.

V. There should be no change to the present 91/9% ECAC/AER split.

VI. A 60-day lead time to estimate the reliability requirement of PG&E's fuel oil supply is reasonable.

VII. The proposed change to PG&E's ECAC/AER revision dates will be addressed in a separate decision.

VIII. The Commission adopted a new resource forecast for PG&E's 1987/88 ECAC/AER. A summary of this forecast is set forth in Exhibit B.

IX. For the forecast period, the Commission adopted ECAC/AER/ERAM revenue increases of $53.6 million, $3.2 million, and $210.2 million, respectively. However, these amounts are deferred and will not be reflected in increased rates at this time.

Procedural Summary

Following a prehearing conference on April 30, 1987 and 13 days of evidentiary hearings between June 22 and August 7, 1987, Phase 1 of these consolidated proceedings was submitted upon filing of concurrent briefs on August 11, 1987. Briefs were submitted by PG&E, the Commission's Public Staff Division (PSD), the California Cogeneration Council (CCC), and a consortium consisting of Santa Fe Geothermal, Inc., Union Oil Company of California, and Independent Energy Producers Association (SF/U/IEP). The CCC and SF/U/IEP represent the interests of various QF projects that sell power to PG&E. In addition to PG&E and PSD witnesses, Kathleen Treleven of Morse, Richard, Weisenmiller & Associates presented testimony on behalf of CCC, and Mark Henwood of Henwood Energy Services, Inc. (HESI) presented testimony on behalf of SF/U/IEP.

Background Information

Payments to QFs for power generated is based on PG&E's avoided energy costs which will determine the IER in this proceeding.

The value of QF power is equal to the utility's avoided costs, i.e. the costs of the resources that the utility would have relied upon but for the power provided by QFs. Because competing resources have a range of costs, the underlying assumptions concerning the balance of loads and resources have a critical impact on the determination of the value of QF power. In this phase of the ECAC proceeding, the parties take issue with several of PG&E's key assumptions which, allegedly, exaggerate the availability of resources with low operating costs.

The IER is derived by dividing the avoided cost by the fuel cost, and is expressed in British thermal units/kilowatt-hour (Btu/kWh). Production cost simulation models are used to determine avoided cost. In determining avoided cost, numerous assumptions about loads and resources are input into the computer model. Since the avoided cost can vary widely depending on what assumptions are put into the model, most of the controversy relates to these assumptions.

Fortunately, a number of forecast issues were uncontested or agreed upon by the parties. We will not address these, but instead will discuss the issues where there is disagreement.

I. Nuclear Plant Operations

It should be noted that as the assumed level of performance for the nuclear power plants is increased, avoided energy costs are decreased. Both units of Diablo Canyon and the Rancho Seco unit are the largest baseload power plants contributing to the PG&E resource base. Consequently, assumptions about their performance have a significant impact on the calculation of avoided energy costs and the IER.

A. Rancho Seco

PG&E proposed a capacity factor for Rancho Seco of 30.6%. PSD, based on its investigation of the current status of Rancho Seco, recommended zero percent. CCC and SF/U/IEP supported the PSD position.

PG&E notes that its forecast reflects Sacramento Municipal Utility District's (SMUD) latest announcements. Based on a very recent conversation between the manager of PG&E's power control and his counterpart at SMUD, as well as SMUD's most recent public statements, PG&E's witness testified that forecasting the plant coming on line in late January with ascension to full power in late June was reasonable. To reflect the power ascension, PG&E estimated the plant's initial output ceiling at 10% of its rating and then increased it each month until the plant was assumed to operate at full capacity in June. In addition, PG&E limited availability to 50% of the hours in each month from January to June, with the availability factor in July reaching 65%. On this basis, PG&E estimated that the resulting capacity factor for Rancho Seco during January through July 1988 would be 30.6%.

PSD recommends that no generation from SMUD's Rancho Seco nuclear facility be included in the adopted forecast of the resource mix. PSD's witness noted that an extensive set of tests has been scheduled at the plant, and the Nuclear Regulatory Commission (NRC) has indicated that this testing is expected to reveal additional problems with the facility. Furthermore, the SMUD board recently replaced the chief of the Rancho Seco restart program, characterizing the program as having poor scheduling, control, and coordination.

Further, PSD points out that at a June 18 board meeting SMUD's Chief Executive Officer (CEO) of nuclear operations presented his proposed schedule and budget for restarting the plant. He stated that given a restart budget of $240 million in 1987, and $85 million in 1988, the plant can begin generating power in late January 1988. Also, the CEO identified five areas which could potentially impact both the restart date and budget. These five areas are related to personnel, testing, licensing, program scope change, and documentation issues.

CCC argues that PG&E has a propensity to overestimate Rancho Seco's performance in these proceedings. CCC notes that for the previous 1986-87 ECAC period, PG&E estimated Rancho Seco would operate at 61% capacity factor; Rancho Seco's actual capacity factor was zero.

Also, CCC contends that PG&E has attempted to obscure its nuclear forecasts by failing to base its nuclear forecasts on capacity factors, and compounding the confusion by misusing the term "availability." Further, CCC notes that SMUD has not yet approved Rancho Seco's budget and the plant will be subject to a shutdown in the event a local initiative is passed by the voters. Accordingly, CCC urges the Commission to assume no generation from Rancho Seco during the 1987-88 ECAC period.

We are satisfied that PSD has thoroughly investigated the Rancho Seco situation. Keeping in mind that Rancho Seco is shut down so that modifications can be made to meet NRC safety requirements, and given the contingencies enumerated by PSD, we find the PSD/CCC position more persuasive. It does appear to us that PG&E is simply taking the most optimistic view possible based on SMUD's pronouncements. Accordingly, for purposes of this forecast period which ends July 31, 1988, we adopt no generation from Rancho Seco.

With regard to CCC's argument that PG&E is misusing the term "availability" in a manner contrary to the California Energy Commission definition, we conclude that the Commission's Evaluation and Compliance Division (E&C) should submit a set of proposed definitions to all interested parties, take comments, and then issue the adopted definitions for use in future ECAC proceedings.

B. <u>Diablo Canyon</u>

PG&E and PSD agreed upon the same forecast of operations for Diablo Canyon Units 1 and 2. PG&E estimates an operating cycle capacity factor of 75%. However, CCC and HESI, based on their analysis, estimate a full cycle capacity factor of 56.4%. PSD supports PG&E's estimate.

PG&E states that Unit 1 will go out for refueling during the period April to June 1988, while no refueling of Unit 2 will occur during the 1987-1988 ECAC/AER forecast period. Both PG&E and

PSD have incorporated this information for Diablo Canyon into their forecasts.

PG&E's operating cycle capacity estimate of 75% is based on a study of eight post-Three Mile Island (TMI) four-loop Westinghouse pressurized water reactors, which are the same type of reactors as the units at Diablo Canyon. PG&E adjusted the study group to eliminate several situations which are not relevant to Diablo Canyon. The first is a prolonged, ongoing outage at Sequayah Units 1 and 2 which is due to documentation, design control, and environmental problems not existing at Diablo. The second is a first cycle outage at McGuire caused by a steam generator problem unrelated to the equipment at Diablo. As a result of these adjustments, PG&E contends that the study group data is representative of what could happen at units similar to PG&E's Diablo Canyon units.

PG&E explains that the terms "operating cycle capacity factor" and "production factor" refer to the plant's operations during all periods except for refueling outages. For purposes of this proceeding, these two terms are synonymous. In contrast, "full cycle capacity factor" refers to the plant's operations at all times, inclusive of refueling outages.

PSD made an independent analysis using the same approach as PG&E. PSD updated the data in PG&E's study as of May 31, 1987, and added Diablo Unit 2 into the data base. Also, PSD investigated the average production factor of all U.S. commercial operating pressurized water reactors of post-TMI vintage greater than 800 MW, and greater than 1,000 MW. PSD reviewed its results and concluded that PG&E's estimate of a 75% production factor (or operating cycle capacity factor) for the Diablo units was reasonable.

CCC argues that aside from the capacity factor-versus-availability-versus-production factor confusion mentioned with regard to Rancho Seco above, PG&E has attempted to evade Commission directives regarding the data upon which power plant forecasts are to be based. CCC notes that in Decision (D.) 86-07-004 the Commission approved two methods for forecasting the performance characteristics of power plants: (1) if a plant has operated for five years, the forecast should be based on the five-year historical average for that specific plant; or (2) if five years of operating data are not available, the forecast should be based on an industry average. Since Diablo Canyon is barely two years old, the requisite five years for reliable plant specific data is unavailable. Consequently, CCC contends that the industry average should be used to forecast the capacity factor for Diablo Canyon.

CCC further argues that PG&E's average, limited to "eight large Westinghouse-manufactured units that have been placed in commercial operation since 1981 and have been in commercial operation for more than one year," has no validity.

First, CCC contends that PG&E improperly limits the data to Westinghouse units. According to CCC, this limitation is inappropriate, because the performance of a plant depends upon a host of variables, only one of which is the plant manufacturer. The general contractor, the quality of the managerial personnel, the quality of the operating and maintenance personnel, the personnel training programs, the political and environmental context, and other economic factors all affect plant performance. CCC contends that no single factor is dominant. Each of those factors and many other factors relate to the capacity factor of the industry average. Therefore, according to CCC, PG&E's attempt to disaggregate the variable (namely, the plant manufacturer) ignores the existence of the many other variables.

Second, even if a Westinghouse-only data set were somehow appropriate, there is no reason to arbitrarily limit the Westinghouse units to those placed in operation since 1981 following the TMI incident. PG&E offered no evidence that design changes in post-TMI units has occurred or that these assumed changes have correlated into improved capacity factors. In addition, CCC points out that TMI was designed by Babcock & Wilcox, while Diablo Canyon is a Westinghouse design.

Third, even if post-1981 units were a valid data set for beginning performance management, PG&E has also limited the data set to plants of 1,000 MW and larger capacity and to plants having "four loops." CCC contends that PG&E offered no acceptable explanation to justify these particular limitations.

Fourth, even if PG&E could theoretically limit the data set to the eight post-1981, larger-than-1,000 MW, and four-loop Westinghouse reactors, the data set would only be reliable if a valid operating history existed for each of the units included in the data set. A review of PG&E's data set shows only three of these reactors were in operation longer than five years.

Fifth, even if the eight-plant data set were otherwise acceptable, PG&E has not sufficiently justified the exclusions from the data base related to Sequayah Units 1 and 2, and McGuire.

In summary, CCC's position is that attempts to rationalize or debate the appropriateness of including or excluding individual units influencing performance histories - such as the ones at Sequayah or McGuire - would result in an endless task. The preferable method to endless debate in adopting valid forecasts is to use a straightforward industry-wide average.

Accordingly, CCC's witness provided an industry-wide average time- and capacity-weighted capacity factor. CCC's factor gives greater weight to the capacity factor of a seven-year-old 1,000 MW plant than to the capacity factor of a five-year-old 800 MW plant, and is based upon a Design Electric Rating average, which, according to CCC, is the preferable average, because it does not vary with changing plant conditions. Consequently, CCC argues that for Diablo Canyon Units 1 and 2 the Commission should adopt its calculated capacity factor of 56.4%.

Both PG&E and PSD note that CCC's stated objective was to develop a broad based, stable, averaged condition forecast. In so doing, however, PG&E and PSD contend that CCC has ignored information already known about Diablo Canyon operations in the forecast period and has relied on nuclear plants that are very different from the Diablo Canyon units.

First of all, PG&E and PSD point out that CCC's use of a 56.4% full cycle capacity factor includes refueling outages. As a consequence, CCC would treat both Diablo Canyon units as undergoing refueling during part of the forecast period and would reduce production from both reactors commensurately. That assumption is not correct.

Second, CCC's weighted average for all U.S. nuclear plants also introduces many factors into their forecast which do not reflect conditions applicable to Diablo Canyon. The CCC methodology places more weight on old, pre-TMI plants which went on line as early as the early seventies. Consequently, CCC has failed to consider the differences which TMI in 1979 brought to the design, engineering, construction, and operation of nuclear plants - even though TMI is an important turning point in the nuclear power industry.

Third, CCC's witness included in her data base all nuclear power plants regardless of type or manufacturer to develop her average even though she agreed that reactors produced by different manufacturers vary in their performance.

Fourth, CCC's reliance on D.86-07-004 forecasting guidelines is misplaced. That decision involves the development of long-run Standard Offers (SO 4) to govern sales of electricity by QFs. Those long-run offers involve multi-year time spans whereas the ECAC proceeding concentrates on a specific short-term forecast.

We agree with PG&E and PSD that for purposes of ECAC proceedings the estimate of available energy resources should be an "as-expected" forecast. Such a forecast is a short-term forecast and should reflect all known conditions such as scheduled maintenance and refueling. Therefore, we conclude that the forecast methodology set forth in D.86-07-004 is not appropriate for annual IER adjustment purposes. While we do not rule out use of industry-wide average capacity factors, we find that PG&E's forecast best accounts for as-expected operations during the forecast period. Accordingly, we will adopt PG&E's estimated 75% operating cycle capacity factor for Diablo Canyon Units 1 and 2.

II. Utility Electric Gas Rate (UEG)

In order to develop a revenue requirement forecast, it is necessary to forecast the cost of gas to PG&E's power plants during the forecast period. This year, that forecast is complicated by the Commission's ongoing gas OII implementation proceeding wherein the Commission is developing new rate structures and levels for implementation sometime within the next half year.

In the interests of proceeding with this case and avoiding unnecessary, duplicative litigation of steam plant gas rate issues here, PG&E and PSD adopted a stipulation for the utility electric gas rate which sets forth agreed upon gas pricing assumptions for this case (Exhibit 10). The stipulation contains both fixed demand charge amounts and variable commodity rates for PG&E's steam plants.

CCC did not join in the UEG stipulation. Rather, CCC believes that the Commission should adopt a specific fuel price forecast of $2.69/MMBtu. This figure is the average figure derived by application of the UEG gas rate stipulation to PSD's resource forecast. Since we know that because of the variable commodity rate the average price must change with the resource forecast we adopt, we decline to adopt CCC's proposal.

SF/U/IEP notes that the cost to PG&E's electric power plants of that natural gas is currently a function of Gas Rate Tariff G-55, which bases the cost of gas to PG&E's power plants on both "fixed" and "variable" charges. The question whether QFs avoid the entirety of these charges under the G-55 tariff will be the subject of hearings pursuant to OIR 2 scheduled to commence early in 1988. SF/U/IEP agrees that pending a contrary determination as a result of those hearings, and consistent with the Commission's current policy, PG&E's electric production costs attributable to the combustion of natural gas should be calculated utilizing the weighted average UEG rate.

Further, SF/U/IEP states that since the purpose of the QFs-in/QFs-out methodology used in this proceeding is to determine the change in total system production costs attributable to the contribution of energy by variable priced QFs, it is apparent that the same average gas price assumption must be made in both the QFs-in production simulation and the QFs-out production simulation. According to SF/U/IEP, PG&E witness Kerler presented a calculation (Exhibit 3, p. 3, Table 1, Case 2) which correctly treats gas price assumptions in the QFs-out case. No party contested the correctness of relying on the same weighted average UEG rate in both the QFs-in and QFs-out cases in calculating QF energy prices, and SF/U/IEP requests its reaffirmation.

We affirm that, at this time, parties should use the methodology consistent with Exhibit 3, p. 3, Table 1, Case 2 to calculate average UEG gas costs. Also, since no party offered any alternative other than the CCC proposal, we will adopt the UEG gas rate stipulation, Exhibit 10, for purposes of the resource forecast and AER revenue requirement calculation. For Phase 2, parties may adjust Exhibit 10 to reflect the underlying volumetric change resulting from the adopted resource forecast.

III. Forecasts of QF Energy Deliveries

Several parties addressed the issue of the appropriate forecasted amount of QF energy deliveries during the 1987/1988 ECAC forecast period.

The forecast for QF production is important, because the higher the QF forecast, the lower the avoided costs. An overly optimistic level of QF generation would ultimately result in underpayments to QFs.

A. The Forecasts of QF Deliveries From Operational QFs

In developing its forecast of QF deliveries PG&E distinguished between two different classes of QFs. The first class of QFs, called operational QFs, are those QFs which were operational as of December 31, 1986. The second class of QFs, called nonoperational QFs, are those QFs which were not operational as of December 31, 1986, but are expected to become operational during the forecast period.

1. Large Geothermal QFs

After initial disagreements, all parties accepted PG&E's final estimate. We will adopt PG&E's final estimate.

2. Operational Wind Projects

After initial disagreement all parties accepted PG&E's final estimate. We will adopt PG&E's final estimate.

B. The Forecasts of QF Deliveries From Nonoperational QFs

By the close of the hearings in the forecast phase, the parties were very close to agreeing on a forecast of QF deliveries from nonoperational projects, as well. However, there remained an issue involving four large thermal QFs for which PG&E had not verified start of construction dates when the hearings began.

1. Nonoperational Wind QFs

Following PG&E's acceptance of PSD's forecast reliability index factor of 0.6, all parties accepted PG&E's estimate. We will adopt PG&E's estimate.

2. Nonoperational Thermal QFs

Based on information presented by PSD and subsequent investigation by PG&E, PG&E modified its position regarding expected deliveries from one large dispatchable thermal QF project. PG&E reduced its forecast of QF deliveries by 178.9 gigawatt-hour for this project. All parties accepted PG&E's adjusted estimate. We will adopt this estimate.

Following submission of data requests by HESI, on behalf of SF/U/IEP, PG&E made a substantial downward revision to its QF generation forecast. HESI accepted PG&E's final position with respect to all of the nonoperational projects but four, the projects with (PG&E workpaper) I.D. Nos. 15, 16, 24, and 25 (Exhibit 15B, p. 3). Thus, in the end, the only dispute concerning nonoperational QFs involved these four projects.

SF/U/IEP points out that the four projects are thermal projects which have not yet commenced construction. SF/U/IEP contends that in the absence of a counter-indication, of which none exists on this record, it must be assumed that the construction of a thermal project of any size will require 14 months to conclude. In addition to the improbability of construction completion and operation of these four thermal QF projects within the ECAC period, SF/U/IEP notes that there is uncertainty respecting completion of interconnection facilities necessary to commence parallel operation and sales of energy to PG&E.

CCC supports the HESI position that these four thermal projects will not be on line during the forecast period. Accordingly, CCC recommends adoption of HESI's QF generation forecast. This total differs from PG&E's only to the extent that HESI assumes no generation from the four nonoperational projects.

We are not convinced by PG&E's testimony that these four thermal units will be on line during the forecast period. Accordingly, we conclude that HESI's QF generation forecast is reasonable and should be adopted.

C. The Forecasts of Energy and Capacity
<u>Expense Associated with QF Deliveries</u>

With regard to pricing of the forecasted QF energy deliveries, the final number should be calculated when the revenue requirement is updated in Phase 2.

The most significant variables in forecasting QF energy and capacity expenses are (1) IERs, (2) as-delivered capacity payments, and (3) the G-55 or UEG rate. With respect to both the IER and as-delivered capacity price, the Commission has adopted numbers to be used through January 1988. For the remainder of the forecast period, February through July 1988, PG&E has forecasted an as-delivered capacity price of $42 per kW-year (Exhibit 1, p. 4-12). This as-delivered capacity price is the same as the one currently in effect. No party has presented any other position.

We will adopt an as-delivered capacity price of $42 per kW-year for this forecast period.

With respect to IERs, as stated previously, we will use the methodology in PG&E's Exhibit 3, p. 3, Table 1, Case 2 for the February through July 1988 portion of the forecast period based on the QF in-out methodology. The numbers should reflect the resource mix and resulting average gas price adopted by the Commission in this Phase 1 decision.

Also, as stated previously, the UEG stipulation, Exhibit 10, will be used to develop utility steam plant gas cost.

IV. The Split of Forecasted QF Deliveries Into Fixed and Variable Components

For the purpose of developing the actual IERs to be used for QF payments, which will be done in Phase 2 of this ECAC proceeding, the forecast of energy delivered by QFs during the 1987/1988 ECAC forecast period must be broken down into two energy payment categories. The two categories are the amount of energy delivered under fixed prices and the amount delivered under variable prices.

The distinction is important when developing IERs using the QF in-out methodology because all QFs which are paid under fixed prices remain in the resource mix, when doing the QF-out run necessary to calculate the IERs. That is, the only resources that are taken out when doing the QF-out run are those QFs with variable prices.

Since the actual split of QF deliveries between fixed and variable cannot be determined until the total QF energy delivery forecast is set, arguing over the specific numbers in each party's final position at this time is not constructive. (The parties' final positions are set forth on p. 2 of Exhibit 15A, the Comparison Exhibit.)

However, once the method for determining the fixed/variable split is established, then the calculation of the actual numbers from the total forecast, once it is set, will become no more than an algebraic exercise. This calculation could be performed when the revenue requirements are updated.

There are only two disputed issues concerning the fixed/variable split methodology. The first concerns the appropriate treatment of those QFs operating under Payment Option 3 (PO 3) of Standard Offer 4 (SO 4). The second concerns the appropriate allocation between fixed and variable power deliveries by QFs less than 1 MW in size. We will address these two issues.

A. Allocation of QF Energy Delivered Under Energy Payment Option 3 of Standard Offer 4 (PO 3 of SO 4)

Turning to those QFs receiving energy payments under PO 3 of SO 4, PG&E's position is that all energy delivered by such QFs should be treated as fixed. According to PG&E, the fact that a QF under PO 3 coincidently receives exactly the same payment as a QF who is treated as variable does not indicate that the energy delivered by that QF should be classified as variable. The reason is that under PO 3, the QF has a significant amount of certainty associated with its energy payment, whether or not the QF has chosen a positive band width.

Further, PG&E submits that if a QF chose a band width of zero, the QF has absolute certainty, and no one disputes that these QFs should be treated as fixed. If a QF has a wider band width, however, it still has certainty associated with its payment. Because of the band width ceiling, its payments can go no higher than a certain limit (depending of course on the UEG rate), and no lower than a certain limit.

PG&E argues that as a practical matter, drawing such a distinction depending on band width almost certainly would not have any impact on the IER calculation. Currently, less than 1% of the payments would go for energy delivered under PO 3 which would be considered to be variable if the band width distinction were drawn. Therefore, according to PG&E, in the interest of administrative efficiency, it is reasonable to treat all energy under PO 3 of SO 4 as fixed payments.

We note that in its final position in its late-filed exhibit, Exhibit 15B, HESI accepts PG&E's position, at least to some extent. Therefore, for the sake of administrative efficiency, for purposes of this proceeding, we will adopt PG&E's position that all energy delivered under PO 3 of SO 4 is fixed.

B. Allocation of Energy Delivered
By QFs Less Than 1 MW in Size

Turning to the energy deliveries from QFs under 1 MW, PG&E's position is that these QFs should be treated as 50% fixed, 50% variable. PG&E's position is not based on a contract-by-contract analysis for these smaller contracts. It reflects the fact that both fixed and variable priced energy is generated by the small QFs and the 50/50 split was a simplification assumption.

HESI originally supported a 0% fixed/100% variable split. However, HESI, after conclusion of the hearings, did an analysis of these QFs' distribution of fixed and variable price contracts based on PG&E's Cogeneration and Small Power Production Quarterly Report, Fourth Quarter, 1986. According to HESI, the result of that analysis is a 30% fixed, 70% variable split for energy deliveries from projects less than 1 MW.

SF/U/IEP contends that since only HESI's latest estimate reflects empirical data it must be adopted.

PG&E objects that HESI's latest estimate was not presented at hearing, and PG&E had no chance to cross-examine HESI on it since it was included in a late-filed exhibit. By contrast, PG&E's position was articulated during the hearings by PG&E's witness, Ms. Andrews. She was available for cross-examination. Her cross-examination did not ellicit any information which argued for the 70/30 split rather than the 50/50 split. Therefore, PG&E contends that its 50/50 split should be adopted.

PG&E's objection overlooks the fact that the late-filed exhibit was provided for at hearing without objection. If PG&E had an objection when it received the late-filed exhibit, or if it wished to cross-examine on it, its remedy is to file a motion to reopen the proceeding for that purpose. Absent such objection or request to cross-examine, late-filed exhibits are received in evidence and may be relied upon to the same extent as any other exhibit received in evidence at hearing. An objection raised in brief is not timely. However, in this case PG&E's objection is made moot by our adoption of PG&E's position that a 50/50 split should be used as a simplification assumption.

V. PG&E's Proposal for 100% ECAC Treatment

PG&E requested that its ECAC percentage be increased to 100% and its AER percentage be reduced to zero. PG&E currently has 91% ECAC balancing account treatment of energy expenses and a 9% AER.

PG&E's AER provides for the recovery of 9% of the forecast period electric energy and associated expenses (as described under ECAC). There is no balancing account associated with the AER. To minimize the revenue risk resulting from the potential for substantial swings in energy-related expenses (primarily due to hydro availability), the allowable pre-tax earnings fluctuation (up or down) resulting from the AER procedure is limited to a 140-basis points cap applied to the equity portion of total rate base. To the extent that AER-related energy expenses exceed the earnings cap, such expenses become fully subject to ECAC balancing account treatment. To put it simply, PG&E's shareholders have a stake in 9% of the forecast period fuel expenses.

PG&E states that it made the request because the Commission's contemplated changes to the fundamental nature of UEG rates in the gas implementation case create a great degree of uncertainty in ECAC forecasting. And that uncertainty has the potential for significant dollar impacts. Therefore, to prevent the ratepayers and shareholders from either gaining a windfall or suffering an undeserved burden, PG&E proposed subjecting all its energy costs and purchased power expense to the ECAC balancing account. PG&E believes that its proposed changes in ECAC and AER percentages are the most equitable and reasonable way to handle the uncertainty created by the Commission's own gas implementation proceeding.

According to PSD, an AER provides a real incentive for the utility to minimize fuel costs. Both ratepayers and shareholders can benefit by good company management of fuel costs if an AER is in place. PSD points out that the AER is not a one-way street. PG&E's shareholders can gain as well as lose from the AER. Past gas rate changes, particularly UEG rate reductions, have benefited PG&E's shareholders through the AER (Exhibit 5, p. 5). PSD submits that the Commission should not reverse its policy on the AER because PG&E believes that its shareholders might now be at risk.

PSD notes that PG&E's sole criterion for requesting elimination of the AER is the uncertainty of the outcome in the current Gas OII/OIR implementation proceeding. Because of the alleged uncertainty, PSD met with PG&E and arrived at a stipulated UEG gas rate (Exhibit 10). PSD points out that the stipulated rate is above PSD's recommended rate in its original showing. Therefore, according to PSD, the stipulation sets forth a negotiated rate which fairly represents the interests of the parties involved and the negotiated rate accounts for any uncertainty concerning the gas proceeding results.

PSD argues that the AER does not pose a big risk to PG&E. The current ECAC/AER increase of $83.55 million is less than 2% of total revenue, out of which the AER portion is less than .1% (Exhibit 5, p. 5). An even smaller percentage increase is due to changes in gas rates. With this small AER portion, PSD contends that even a big swing in gas rates from the stipulated level would not harm PG&E.

SF/U/IEP notes that the proposed reduction of the AER percentage to zero would result in relieving utility shareholders of any financial risk associated with the accuracy of the ECAC forecast, which is the same forecast utilized to set IERs necessary to calculate QF energy prices.

SF/U/IEP thinks there is great merit to continuing the practice of utilizing the ECAC for the purpose of estimating production expenses and the resultant IERs used to calculate QF energy prices. All of the forecasts required to determine and fix energy prices to QFs are necessarily a part of every ECAC. In the absence of an AER percentage of sufficient magnitude that utility shareholders have a financial stake in the accuracy of the forecasts, the use of the ECAC to calculate IERs would subject QFs to a significant risk of erroneous and low forecasted IERs. Accordingly, SF/U/IEP recommends in strongest terms that a positive AER percentage be retained in order that utilities and QFs have mutual interest in the accuracy of the forecast generated in these ECAC proceedings.

CCC supports PSD's recommendation against the AER elimination and echoes the SF/U/IEP cogenerator position with regard to the need for PG&E to have a stake in the ECAC forecast so that PG&E has an incentive to submit an accurate forecast.

We conclude that PG&E shareholders should continue to have a stake in the ECAC/AER forecast and, with the UEG stipulation discussed above, the uncertainty with regard to fuel costs has not changed sufficiently to warrant any change in the AER at this time.

VI. Fuel Oil Inventory Volumes

A. The Significance of the Differences in Oil Resupply Time Requests Between the Staff and PG&E

Fuel oil inventory was one of the most hotly contested issues in Phase 1 of these proceedings. PG&E and PSD differ on both the forecast of fuel oil inventory volumes and PSD's proposed ratemaking/accounting treatment of oil inventory carrying costs and oil sale losses and gains. The ratemaking/accounting issues will be addressed in a separate decision. The difference in fuel oil inventory volumes is addressed here.

PG&E has recommended a forecast oil inventory volume of 6 million barrels; the PSD recommends 5.65 million barrels. The difference is entirely due to different assumptions by PG&E and PSD regarding the time needed to resupply fuel oil. PSD proposes to use 60 days; PG&E contends that 90 days should be used. The 30-day difference between PG&E and PSD translates into the need for an additional 350,000 barrels of oil to protect reliability of service under possible adverse conditions.

PG&E points out that the resupply time assumption is primarily of concern during the winter months. It is during those months that fuel oil supply requirements peak and the utility could incur unplanned extraordinary fuel oil burns. If those winter burns occurred, the utility would need to obtain additional oil supplies in time to meet subsequent winter months' reliability needs since adverse conditions in these later months could require further oil burns. Therefore, the oil resupply time assumption must be viewed in terms of winter period conditions.

Further, PG&E states that the resupply time assumption must also be based on the time needed to secure .5% sulfur oil since that is the type of oil PG&E must use in all its steam plants except Humboldt and Kern. According to PG&E, this particular sulfur specification plays an important role in limiting likely sources for fuel oil and determining the time needed to resupply PG&E's oil inventory.

PSD states that its 60-day lead time recommendation stems from numerous factors.

Particularly, PSD notes that in response to a data request, PG&E replied as follows:

> "The Company's only LSFO cargo purchase since deliveries under the Chevron contract were discontinued in April 1982 was the spot

> purchase during 1986 of 285,000 barrels of LSWR which originated in Singapore. In this case, PG&E agreed to the purchase on July 25, the cargo was delivered to PG&E's Pittsburg Power Plant by a 54,402 deadweight ton vessel on September 4. <u>The total lead-time for delivery of this cargo was 41 days.</u>"
> (Ex. 5, p. 82) (Emphasis added.)

PSD observes that in addition to the 60-day lead time recommended, it had already incorporated a 14-day fuel supply contingency resulting, in essence, in an allowance of almost 75 days' fuel oil inventory to replenish inventory.

PSD further cited both San Diego Gas & Electric Company's (SDG&E) and Southern California Edison Company's (Edison) recent ECAC applications. Both have requested 60-day average lead times.

PG&E argues that PSD's reference to SDG&E and Edison is inappropriate. SDG&E's oil burns are much smaller than PG&E's and have a better chance of being met by West Coast refining resources. And Edison's situation is quite different with regard to oil contracts, the ability or lack thereof to move oil from plant to plant, customer demand, and gas storage access. Also, according to PG&E, the 41-day delivery cited by PSD occurred under summer conditions when the market had hit a low. The spot market in Singapore was greatly distressed and surplus prices were at their lowest point in years. In other words, all elements needed for that transaction were ready when PG&E wanted them and there were no delays. According to PG&E, that is unlikely to be the situation if the company were seeking oil supplies in winter when adverse conditions were triggering need for oil.

Further, PG&E argues that PSD has premised its proposed 60-day resupply period on the assumption that oil demand will be low and the utility would have no problem securing oil. According to PG&E, that assumption is contrary to the contingency that PG&E is trying to plan against by maintaining the reliability portion of fuel oil inventory. Under adverse conditions, when energy supply conditions trigger a need for oil, PG&E submits that one cannot assume that oil will be easily and readily available on the spot market.

We note that the PSD recommendation is also based on the following reason:

> "Deregulation of the natural gas industry and air pollution considerations make fuel oil a less competitive alternative to the utilities. PG&E itself is projecting fuel oil to cost more per MMBtu than natural gas through the forecast period. The demand for oil is not likely to be strong." (P. 82, Exhibit 5.)

We find the above argument particularly persuasive, at this time, given that Diablo Units 1 and 2 are both in operation and that gas has displaced the use of fuel oil in PG&E's steam plants. Accordingly, we are not convinced that a 90-day resupply time is needed. Therefore, we will adopt PSD's recommended 60-day resupply period as reasonable.

We fully realize that the fuel supply situation can change rapidly. If the situation deteriorates significantly, PG&E may request that this issue be reviewed and the 60-day limitation changed. Such a request may be made in any ECAC application, or if there is an emergency, PG&E may petition to modify this decision.

VII. Proposed Change in Forecast and Review Periods

PSD has proposed to change PG&E's revision date from August 1 to September 1 in order to allow additional time for the publication of the ALJ's proposed decision under Public Utilities Code Section 311. PG&E agrees with that change. To clarify PSD's proposed schedule, PG&E also proposes to move the ECAC trigger filing revision date from February 1 to March 1. Concurrently, PG&E further proposes to improve the procedural schedule by changing its reasonableness review period for electric and gas operations from a February 1 - January 31 cycle to a calendar year basis.

According to PG&E, use of a calendar year for reasonableness review purposes would allow the company to use data already generated for its calendar year and would eliminate the extra work now necessary to develop data for the special February 1 - January 31 period. Consequently, PG&E submits that its proposal would make the reasonableness review process easier for both PG&E and the PSD.

We will address this matter in a subsequent decision after we have reviewed the ECAC filing schedules of the other major energy utilities.

VIII. Adopted Resource Forecast

A summary of the adopted resource forecast for PG&E's ECAC/AER period August 1, 1987 to July 31, 1988 is set forth in Appendix B. This summary reflects the adopted decisions with regard to the contested issues, and the uncontested items as set forth in Exhibit 15.

The adopted resource forecast will be the basis for the production cost modeling in Phase 2 of this proceeding, which will determine PG&E's avoided cost, which will, in turn, be used to calculate the IER for power delivered to PG&E from QF projects and payments made to QF customers through July 31, 1988.

IX. ECAC/AER/ERAM Revenue Requirements

PG&E requested an ERAM increase of $210.2 million. Also, PG&E requested that its ECAC percentage be increased from 91% to 100%, and its AER percentage be decreased from 9% to zero.

In the alternative, PG&E requested that if its request to reduce the AER to zero is denied, then in addition to the ERAM increase of $210.2 million, it should receive an AER increase of $5.8 million.

Further, PG&E stated that it proposed to forego its August 1, 1987 ECAC adjustment because of the uncertainties affecting the gas rate for electric utilities in the Commission's gas OII/OIR proceeding. According to PG&E, depending on the Commission's final decision on the gas rate issues, there can be large swings in the needed revenue requirement. PG&E believes that the great uncertainty created by these matters warrants foregoing any ECAC revenue requirement change at present.

As discussed previously, we concluded that there should be no change in the present 91/9% ECAC/AER split for forecasted energy expense. Having decided this pivotal issue, we now turn to the ratemaking treatment for the ECAC/AER/ERAM components.

<u>ECAC</u>

We note that the August 1, 1987 ECAC adjustment that PG&E wishes to forego is estimated at $53.6 million (Appendix B). We conclude that a revenue shortfall of this magnitude can be accommodated in the ECAC balancing account without causing severe future rate shock. Accordingly, we agree to PG&E's proposal to forego this ECAC adjustment. The resulting undercollection will be carried in the ECAC balancing account for amortization in the next ECAC proceeding.

<u>AER</u>

The adopted AER revenue increase amounts to $3.5 million on an annualized basis. That would equate to a 0.005 cents/kWh if spread to all sales on a uniform cents/kWh basis.

We conclude at this time that a rate increase of $3.5 million does not justify the administrative burden involved with changing rates. However, we instruct PG&E to recover this increase in the ECAC balancing account from the time this decision is effective until the time the $3.5 million AER increase is implemented with the January 1988 ERAM/AER/Attrition rate change.

Starting with the effective date of this decision, PG&E will calculate a proxy for the AER increase based on a total kWh sales from that date valued at a uniform rate of 0.005 cents/kWh. Each month PG&E will charge the amount of AER revenue calculated under the proxy to the ECAC balancing account to be recovered in the next ECAC forecast period. PG&E will terminate this calculation once the $3.5 million is reflected in the January 1, 1988 ERAM/AER/Attrition rate change. The 0.005 cents/kWh pertains to the proxy calculation only and does not represent actual AER rates to be implemented with the January 1, 1988 rate change.

ERAM

With regard to PG&E's requested ERAM increase of $210.2 million, PSD's auditor, having audited PG&E's accounts, takes no exception to this amount. She states that the amount requested is primarily a result of the difference between forecasted and recorded kWh sales. Specifically, sales were forecasted to be 72.1 billion kWh as compared to actual sales of 61.7 billion kWh for the record period. This represented a 17% difference between recorded and forecasted sales. As a result, the ERAM balancing account reflected an undercollection (p. 3-2, Exhibit 8).

We will adopt the $210.2 million ERAM increase as reasonable; however, since PG&E will shortly be filing a request for an Attrition Increase/Decrease for 1988, and since we wish to avoid multiple rate changes, we will defer inclusion of the ERAM increase in rates at this time. We might mention that PG&E will not be "out-of-pocket" since, unlike the AER, ERAM has a balancing account which accrues interest. Accordingly, PG&E may include the $210.2 million ERAM amount in rates at the time it files its 1988 attrition rate change.

Comments on the Proposed Decision of
the Administrative Law Judge (ALJ)

The proposed decision of the ALJ was served on the parties on September 29, 1987. Comments were received from PG&E, PSD, and Union Oil Company of California (Union).

Fuel Oil Inventory Volumes

PG&E takes exception to the ALJ's reliance on the quotation from PSD's testimony set forth at page 24 of this decision.

PG&E states that the quote from PSD, while true, should lead to a conclusion opposite to the one drawn. PG&E and PSD agree that gas is expected to be the fuel of choice on economic grounds. The calculations of fuel oil inventory take this fully into account: fuel oil inventory is maintained only as a backup fuel, in the event of curtailment of gas service to power plants or contingencies affecting the delivery of gas to power plants.

According to PG&E, the draft decision's apparent reasoning is that low demand for oil in PG&E's power plants, under normal conditions and with current competitive fuel prices, will create a surplus of LSFO on the market, resulting in ready availability should oil be needed. PG&E contends that this conclusion is factually in error, and contradicted by the record.

We should point out that the ALJ's proposed decision does not state a reliance on a surplus of LSFO. Rather, PG&E infers that this is the basis for the ALJ's reasoning. However, for clarification we might add that with regard to the quotation cited by PG&E, the ALJ did give some weight to the sentence: "The demand for oil is not likely to be strong." And the conclusion drawn from this statement is that the LSFO market is in a normal situation at this time. The ALJ considered this element along with all the other testimony in arriving at his recommendation.

PSD, responding to PG&E's comments, notes that PSD provided evidence showing that PG&E was able to obtain 285,000 barrels of LSFO, originating in Singapore, with a total lead-time delivery of 41 days. Also, PSD notes that two other major California utilities have requested 60-day lead times, and further, PG&E failed to provide any reason why Chevron could not provide oil prior to a 90-day period. PSD submits that the record before the Commission fully supports a 60-day resupply lead time. Accordingly, PSD recommends that the Commission maintain the 60-day resupply period as being reasonable.

In summary, we are not persuaded that PG&E needs more than a 60-day resupply lead time. As we stated previously, PG&E may request that this issue will be reviewed if the LSFO market deteriorates significantly.

Geothermal Steam Price

Union requested that the ALJ's proposed decision be modified to state that the revenue requirement therein is not a Commission determination of the respective rights and obligations of PG&E or Union under their steam sales contract for the Geysers. The contract between PG&E and Union is currently the subject of a lawsuit in California state court.

PG&E and PSD note that for purposes of the revenue requirement in this case, they estimated what was believed to be the appropriate costs under the Geysers steam contract with Union for the forecast period. PG&E and PSD submit that the controversy between PG&E and Union does not require any changes to be made in the revenue requirement in the ALJ's proposed decision.

Accordingly, we will state for the record that the geothermal steam price included in the calculation of PG&E's revenue requirement is simply an estimate and does not reflect any Commission interpretation of the PG&E/Union contract.

Integrating AER Increase in Rates

In its comments on the ALJ's proposed decision, PG&E offered an alternative accounting proposal for the AER increase. PSD supports PG&E's proposal. We adopt this proposal and it is set forth at pages 26 and 27 of this decision.

Corrections to Revenue
Requirement Tables

PSD noted two errors in the tables attached to the ALJ's proposed decision. These corrections are reflected in the tables attached to this decision (Appendix B).

Findings of Fact

1. For purposes of this ECAC/AER forecast period which ends July 31, 1988, there will be no generation from Rancho Seco.

2. For purposes of this ECAC/AER forecast period, Diablo Canyon Units 1 and 2 will achieve a 75% operating cycle capacity factor.

3. For purposes of calculating the IER, the UEG gas rate stipulation, Exhibit 10 adjusted to reflect the underlying volumetric change, should be used with the methodology in PG&E's Exhibit 3, p. 3, Table 1, Case 2.

4. Large thermal QF Projects Nos. 15, 16, 24, and 25 will provide zero generation during the forecast period.

5. A 50/50% split should be used to allocate energy delivered by QFs less than 1 MW in size for purposes of this proceeding.

6. There should be no change to the present 91/9% ECAC/AER split.

7. A 60-day lead time to estimate the reliability requirement of PG&E's fuel oil supply is reasonable.

8. There are certain inconsistencies in the use of definitions by the parties in estimating resulting capacity factors of nuclear power plants. There is a need for consistency in this area to avoid waste of hearing time.

9. For this forecast period, PG&E is entitled to ECAC/AER/ERAM revenue increases on an annualized basis of $56.4 million, $3.5 million, and $210.2 million, respectively.

Conclusions of Law

1. For PG&E's ECAC/AER period August 1, 1987 to July 31, 1988, the resource forecast adopted should be as set forth in this decision.

2. The adopted ECAC/AER/ERAM revenue increases for PG&E should be deferred from inclusion in rates at this time. PG&E may file tariff sheets for inclusion of the AER/ERAM amounts in rates at the time it files its 1988 attrition rate change. The ECAC amount should be included in PG&E's next ECAC proceeding.

3. The adopted resource forecast should be the basis for the production cost modeling in Phase 2 where we will determine PG&E's avoided cost and IER for power delivered to PG&E from QFs.

4. The adopted revenue requirement, which includes an estimate of geothermal steam cost, is not a Commission determination of the respective rights and obligations of PG&E or Union under their steam sales contract for the Geysers.

5. In order to avoid waste of hearing time with regard to definitions related to nuclear power plant operation forecasts, E&C should issue a set of adopted definitions for use in future ECAC proceedings.

INTERIM ORDER

IT IS ORDERED that:

1. For Pacific Gas and Electric Company (PG&E), the adopted resource forecast for the period August 1, 1987 to July 31, 1988 is as set forth in Appendix B.

2. PG&E is entitled to revenue increases related to its Energy Cost Adjustment Clause (ECAC), Annual Energy Rate (AER), and Electric Revenue Adjustment Mechanism (ERAM), as set forth in this opinion. However, these amounts shall not be reflected in rates at this time.

3. PG&E is authorized to file revised tariff schedules at the time it files its 1988 attrition rate change to recover in rates the AER/ERAM revenue increases adopted in this opinion. The revised tariff schedules shall comply with General Order 96-A.

This order is effective today.

Dated NOV 13 1987, at San Francisco, California.

STANLEY W. HULETT
President
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

Commissioner Donald Vial, being necessarily absent, did not participate.

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY.

Victor Weisser, Executive Director

APPENDIX B
Page 1

PACIFIC GAS AND ELECTRIC COMPANY

Energy Cost Adjustment Clause
Adopted Change in Revenue Requirement

Line No.	Revision Date: August 1, 1987 Forecast Period: Twelve Months Beginning August 1, 1987	Estimated Quantity(5)	Estimated Price(6)	$(000)
	Steam Plants			
1	Gas	197,213	$2.7234	$ 537,082
2	Oil-Residual	2,136	2.8820	6,156
3	Oil-Distillate	1,659	3.6950	6,130
4	Subtotal-Fossil	201,008		549,368
5	Geothermal Steam Plants	9,852	.01612	158,859
6	Nuclear Steam Plants	12,671	.00904	114,562
7	Purchased Electric Energy	17,684	.03371	596,169
8	Water for Power	12,558		4,089
9	Oil Inventory Carrying Cost			5,074
10	Write-down of Fuel Oil Inventory			62,464
11	Carrying Cost on Unamortized Write-down			3,464
12	Standby Charges			912
13	Variable Wheeling			289
14	Total Energy Expenses			1,495,250
15	Less 9% of Energy Expenses(1)			134,573
16	Subtotal of Energy Expenses			1,360,677
17	Diablo Stipulation Agreement			137,024
18	91% of Excess Oil Inventory Carrying Cost			
19	Subtotal			$1,497,701

(1) Line 14 x .09
(2) Factor is: .9854
(3) Line 22 x .00774
(4) At rates effective April 1, 1987
(5) In billions of Btu or in gigawatt-hours
(6) In dollars per billion Btu or dollars per kilowatt-hour
(7) Estimated as of July 31, 1987
(8) Write-down expense not included in allocation to FERC

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PACIFIC GAS AND ELECTRIC COMPANY

Energy Cost Adjustment Clause
Adopted Change in Revenue Requirement

Line No.	Revision Date: August 1, 1987 Forecast Period: Twelve Months Beginning August 1, 1987	Estimated Quantity(5)	Estimated Price(6)	$(000)
19	Subtotal (from Page 1)			$1,497,701 ✓
20	Alloc. to CPUC jurisdictional Sale(2)(8)			1,476,710 ✓
21	Energy Cost Adjustment Account Balance			18,908(7)
22	Subtotal			1,495,618 ✓
23	Adjustment for Franchise Fees and Uncollectible Accounts Expense(3)			11,576 ✓
24	Total ECAC Revenue Requirement			1,507,194 ✓
25	Total ECAC Revenue at Present Rates(4)			1,453,635
26	CHANGE IN REVENUE REQUIREMENT			$ 53,559 ✓

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(1) Line 14 x .09
(2) Factor is: .9854
(3) Line 22 x .00774
(4) At rates effective April 1, 1987
(5) In billions of Btu or in gigawatt-hours
(6) In dollars per billion Btu or dollars per kilowatt-hour
(7) Estimated as of July 31, 1987
(8) Write-down expense not included in allocation to FERC

APPENDIX B
Page 3

PACIFIC GAS AND ELECTRIC COMPANY

Adopted Annual Energy Rate Revenue Requirement
Test Year Beginning August 1, 1987
$(000)

Line No.		Updated
1	Carrying Cost of Oil Inventory	$ 5,074
2	Est. Fuel & Purchased Power Expenses	1,490,176
3	Total Energy Expenses	1,495,250
4	9% of Oil Energy Expenses(1)	134,573
5	Alloc. to CPUC Jurisdictional Sales(2)(5)	132,695
6	Adjustment for Franchise Fees and Uncollectible Accounts Expense(3)	1,027
7	Total AER Revenue Requirement	133,722
8	Less AER Revenue Authorized(4)	130,533
9	CHANGE IN REVENUE REQUIREMENT	$ 3,189*

(1) Line 3 x .09
(2) Factor is: .9854
(3) Line 5 x .00774
(4) At rates effective April 1, 1987
(5) Write-down expense not included in allocation to FERC

* Revenue Requirement divided
by sales: M$3,472/63,273,843 Mwh = .005¢/kWh

(END OF APPENDIX B)

APPENDIX A
Page 1

List of Appearances

Applicant: Shirley A. Woo, Roger J. Peters, and Mark R. Huffman, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Morrison & Foerster, by Jerry R. Bloom and John S. Caragozian, Attorneys at Law, for California Cogeneration Council; David R. Branchcomb and Mark Henwood, for Henwood Energy Services, Inc., Santa Fe Geothermal, Inc., Union Oil Company of California, and Independent Energy Producers Association; Robert E. Burt, for California Manufacturers Association; Karen K. Edson, for KKE and Associates; Eric Eisenman, for Transwestern Pipeline, Inc.; Michel Peter Florio, Attorney at Law, and Sylvia M. Siegel, for Toward Utility Rate Normalization; Steven A. Geringer, Attorney at Law, for California Farm Bureau Federation; Graham & James, by Martin A. Mattes, and David S. Marchant, Attorneys at Law, for Amerada Hess Corporation; William B. Marcus, for JBS Energy, Inc.; Morse, Richard, Weisenmiller & Associates, by Sarah Nickerson, for Bob Weisenmiller; Kenneth Pickett, for Independent Power Corporation; John D. Quinley, for Cogeneration Service Bureau; Frank J. Cooley and Bruce Reed, Attorneys at Law, for Southern California Edison Company; Donald G. Salow, for Association of California Water Agencies; Chris Siemens, for Power Users Protection Council; Gary D. Simon, for El Paso Natural Gas; Thomas R. Sparks, for Unocal Corporation; James Squeri and David Simpson, Attorneys at Law, for Armour, St. John, Wilcox, Goodin & Schlotz; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Christopher Ellison, Attorneys at Law, for Industrial Users; John K. Van de Kamp, Attorney General of the State of California, Andrea Sheridan Ordin, Chief Assistant Attorney General, Michael J. Strumwasser, Special Counsel to the Attorney General, by Mark J. Urban, Deputy Attorney General, for State of California; John R. Vickland, Attorney at Law, for San Francisco Bay Area Rapid Transit District; Harry K. Winters, for University of California; Matthew Brady and Dian Grueneich, Attorneys at Law, for California Department of General Services; Messrs. Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobilehome Association; Sara Hoffman, for Contra Costa County; Reed V. Schmidt, for California Street Light Association; Hart, Neil & Weigler, by Michael P. Alcantar and Clyde E. Hirschfeld, Attorneys at Law, and Drazen-Brubaker & Associates, Inc., by Donald W. Schoenbeck, for Cogenerators of

APPENDIX A
Page 2

List of Appearances

Southern California; Hanna and Morton, by Douglas K. Kerner, Attorney at Law, for Santa Fe Geothermal, Inc., Union Oil Company of California, and Independent Energy Producers Association; and Barbara Barkovich, for self; interested parties.

Public Staff Division: Bud Alderson, Javier Plasencia, Attorneys at Law, and Mahendra Jhala.

(END OF APPENDIX A)

APPENDIX B
Page 1

PACIFIC GAS AND ELECTRIC COMPANY

Energy Cost Adjustment Clause
Adopted Change in Revenue Requirement

Line No.	Revision Date: August 1, 1987 Forecast Period: Twelve Months Beginning August 1, 1987	Estimated Quantity(5)	Estimated Price(6)	$(000)
	Steam Plants			
1	Gas	198,054	$2.7199	$ 538,686
2	Oil-Residual	2,136	2.8820	6,156
3	Oil-Distillate	2,078	3.7064	7,702
4	Subtotal-Fossil	202,268		552,544
5	Geothermal Steam Plants	9,852	.01612	158,859
6	Nuclear Steam Plants	12,671	.00904	114,562
7	Purchased Electric Energy	17,684	.03371	596,169
8	Water for Power	12,558		4,089
9	Oil Inventory Carrying Cost			5,074
10	Write-down of Fuel Oil Inventory			62,464
11	Carrying Cost on Unamortized Write-down			3,464
12	Standby Charges			912
13	Variable Wheeling			289
14	Total Energy Expenses			1,498,426
15	Less 9% of Energy Expenses(1)			134,858
16	Subtotal of Energy Expenses			1,363,568
17	Diablo Stipulation Agreement			137,024
18	91% of Excess Oil Inventory Carrying Cost			
19	Subtotal			$1,500,592

(1) Line 14 x .09
(2) Factor is: .9854
(3) Line 22 x .00774
(4) At rates effective April 1, 1987
(5) In billions of Btu or in gigawatt-hours
(6) In dollars per billion Btu or dollars per kilowatt-hour
(7) Estimated as of July 31, 1987
(8) Write-down expense not included in allocation to FERC

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PACIFIC GAS AND ELECTRIC COMPANY

Energy Cost Adjustment Clause
Adopted Change in Revenue Requirement

Line No.	Revision Date: August 1, 1987 Forecast Period: Twelve Months Beginning August 1, 1987	Estimated Quantity(5)	Estimated Price(6)	$(000)
19	Subtotal (from Page 1)			$1,500,592
20	Alloc. to CPUC jurisdictional Sale(2)(8)			1,479,559
21	Energy Cost Adjustment Account Balance			18,908(7)
22	Subtotal			1,498,467
23	Adjustment for Franchise Fees and Uncollectible Accounts Expense(3)			11,598
24	Total ECAC Revenue Requirement			1,510,065
25	Total ECAC Revenue at Present Rates(4)			1,453,635
26	CHANGE IN REVENUE REQUIREMENT			$ 56,430

(1) Line 14 x .09
(2) Factor is: .9854
(3) Line 22 x .00774
(4) At rates effective April 1, 1987
(5) In billions of Btu or in gigawatt-hours
(6) In dollars per billion Btu or dollars per kilowatt-hour
(7) Estimated as of July 31, 1987
(8) Write-down expense not included in allocation to FERC

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Page 3

PACIFIC GAS AND ELECTRIC COMPANY

Adopted Annual Energy Rate Revenue Requirement
Test Year Beginning August 1, 1987
$(000)

Line No.		Updated
1	Carrying Cost of Oil Inventory	$ 5,074
2	Est. Fuel & Purchased Power Expenses	1,493,352
3	Total Energy Expenses	1,498,426
4	9% of Oil Energy Expenses(1)	134,858
5	Alloc. to CPUC Jurisdictional Sales(2)(5)	132,976
6	Adjustment for Franchise Fees and Uncollectible Accounts Expense(3)	1,029
7	Total AER Revenue Requirement	134,005
8	Less AER Revenue Authorized(4)	130,533
9	CHANGE IN REVENUE REQUIREMENT	$ 3,472*

(1) Line 3 x .09
(2) Factor is: .9854
(3) Line 5 x .00774
(4) At rates effective April 1, 1987
(5) Write-down expense not included in allocation to FERC

* Revenue Requirement divided
by sales: M$3,472/63,273,843 Mwh = .005¢/kWh

(END OF APPENDIX B)

ALJ/BDP/jt

Decision ____________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Commission order finding that PG&E's gas and electric operations during the reasonableness review period from February 1, 1986, to January 31, 1987, were prudent. (U 39 M)	Application 87-04-005 (Filed April 7, 1987)
Application of Pacific Gas and Electric Company for authority to adjust its electric rates effective August 1, 1987.	Application 87-04-035 (Filed April 21, 1987)

(See Appendix A for appearances.)

INTERIM OPINION

Phase 1

This decision reviews Pacific Gas and Electric Company's (PG&E) electric sales and related fuel and energy costs for the forecast period August 1, 1987 to July 31, 1988. The Commission concludes that PG&E is entitled to electric revenue increases to Energy Cost Adjustment Clause (ECAC), Annual Energy Rate (AER), and Electric Revenue Adjustment Mechanism (ERAM) on an annualized basis of $56.4 million, $3.5 million, and $210.2 million, respectively, for a total of $270.1 million. However, for reasons which are set forth, these increases are deferred and will not be reflected in increased rates at this time.

The $56.4 million amount relates to a 91% portion of fuel and energy related expense increase for the forecast period covered by PG&E's ECAC.

The $3.5 million amount relates to the remaining 9% portion of fuel and energy related expense increase covered by PG&E's AER.

The $210 million amount is to offset underrecovery of fixed operation and maintenance costs (excluding fuel) resulting from lower than forecasted sales, as covered by PG&E's ERAM.

<u>Summary</u>

For purposes of PG&E's August 1, 1987 to July 31, 1988 ECAC/AER forecast, this decision decides the contested issues as follows:

I. Nuclear Plant Operations:

A. Rancho Seco will provide zero generation for the forecast period.

B. Diablo Canyon Units 1 and 2 will achieve a 75% operating cycle capacity factor.

II. For AER revenue requirement purposes, the UEG gas rate stipulation, Exhibit 10, should be used to calculate Incremental Energy Rates (IER) in accordance with the methodology in PG&E's Exhibit 3, p. 3, Table 1, Case 2. For Phase 2 IER calculation, parties may adjust Exhibit 10 to reflect the underlying volumetric change.

III. Large thermal Qualifying Facility (QF) Projects Nos. 15, 16, 24, and 25 will provide zero generation during the forecast period.

IV. A. QF energy delivered under Energy Payment Option 3 (EPO 3) of Standard Offer 4 (SO 4) should be treated as receiving fixed payments for purposes of this proceeding.

B. A 50/50% split (fixed versus variable) should be used to allocate energy delivered by QFs less than 1 megawatt (MW) in size for purposes of this proceeding.

V. There should be no change to the present 91/9% ECAC/AER split.

VI. A 60-day lead time to estimate the reliability requirement of PG&E's fuel oil supply is reasonable.

VII. The proposed change to PG&E's ECAC/AER revision dates will be addressed in a separate decision.

VIII. The Commission adopted a new resource forecast for PG&E's 1987/88 ECAC/AER. A summary of this forecast is set forth in Exhibit B.

IX. For the forecast period, the Commission adopted ECAC/AER/ERAM revenue increases of $56.4 million, $3.5 million, and $210.2 million, respectively. However, these amounts are deferred and will not be reflected in increased rates at this time.

Procedural Summary

Following a prehearing conference on April 30, 1987 and 13 days of evidentiary hearings between June 22 and August 7, 1987, Phase 1 of these consolidated proceedings was submitted upon filing of concurrent briefs on August 11, 1987. Briefs were submitted by PG&E, the Commission's Public Staff Division (PSD), the California Cogeneration Council (CCC), and a consortium consisting of Santa Fe Geothermal, Inc., Union Oil Company of California, and Independent Energy Producers Association (SF/U/IEP). The CCC and SF/U/IEP represent the interests of various QF projects that sell power to PG&E. In addition to PG&E and PSD witnesses, Kathleen Treleven of Morse, Richard, Weisenmiller & Associates presented testimony on behalf of CCC, and Mark Henwood of Henwood Energy Services, Inc. (HESI) presented testimony on behalf of SF/U/IEP.

Background Information

Payments to QFs for power generated is based on PG&E's avoided energy costs which will determine the IER in this proceeding.

The value of QF power is equal to the utility's avoided costs, i.e. the costs of the resources that the utility would have relied upon but for the power provided by QFs. Because competing resources have a range of costs, the underlying assumptions concerning the balance of loads and resources have a critical impact on the determination of the value of QF power. In this oil sale losses and gains. The ratemaking/accounting issues will be addressed in a separate decision. The difference in fuel oil inventory volumes is addressed here.

PG&E has recommended a forecast oil inventory volume of 6 million barrels; the PSD recommends 5.65 million barrels. The difference is entirely due to different assumptions by PG&E and PSD regarding the time needed to resupply fuel oil. PSD proposes to use 60 days; PG&E contends that 90 days should be used. The 30-day difference between PG&E and PSD translates into the need for an additional 350,000 barrels of oil to protect reliability of service under possible adverse conditions.

PG&E points out that the resupply time assumption is primarily of concern during the winter months. It is during those months that fuel oil supply requirements peak and the utility could incur unplanned extraordinary fuel oil burns. If those winter burns occurred, the utility would need to obtain additional oil supplies in time to meet subsequent winter months' reliability needs since adverse conditions in these later months could require further oil burns. Therefore, the oil resupply time assumption must be viewed in terms of winter period conditions.

Further, PG&E states that the resupply time assumption must also be based on the time needed to secure .5% sulfur oil since that is the type of oil PG&E must use in all its steam plants except Humboldt and Kern. According to PG&E, this particular sulfur specification plays an important role in limiting likely sources for fuel oil and determining the time needed to resupply PG&E's oil inventory.

PSD states that its 60-day lead time recommendation stems from numerous factors.

Particularly, PG&E notes that in response to a PSD data request, PG&E replied as follows:

> "The Company's only LSFO cargo purchase since deliveries under the Chevron contract were discontinued in April 1982 was the spot

increase of $210.2 million, it should receive an AER increase of $5.8 million.

Further, PG&E stated that it proposed to forego its August 1, 1987 ECAC adjustment because of the uncertainties affecting the gas rate for electric utilities in the Commission's gas OII/OIR proceeding. According to PG&E, depending on the Commission's final decision on the gas rate issues, there can be large swings in the needed revenue requirement. PG&E believes that the great uncertainty created by these matters warrants foregoing any ECAC revenue requirement change at present.

As discussed previously, we concluded that there should be no change in the present 91/9% ECAC/AER split for forecasted energy expense. Having decided this pivotal issue, we now turn to the ratemaking treatment for the ECAC/AER/ERAM components.

ECAC

We note that the August 1, 1987 ECAC adjustment that PG&E wishes to forego is estimated at $56.4 million (Appendix B). We conclude that a revenue shortfall of this magnitude can be accommodated in the ECAC balancing account without causing severe future rate shock. Accordingly, we agree to PG&E's proposal to forego this ECAC adjustment. The resulting undercollection will be carried in the ECAC balancing account for amortization in the next ECAC proceeding.

AER

The adopted AER revenue increase amounts to $3.5 million on an annualized basis. It equates to a uniform increase of 0.005¢ per kWh (Appendix B).

We conclude that a rate change of 0.005¢ per kWh does not justify the administrative burden involved in changing rates. PG&E should carry this amount in its ECAC balancing account for later inclusion in rates at the same time as its 1988 attrition rate change tariff filing. This amount should be adjusted to reflect the effective date of this decision and be accounted for on a uniform 0.005¢ per kWh basis. Accordingly, this AER increase will not be reflected in rates at this time.

ERAM

With regard to PG&E's requested ERAM increase of $210.2 million, PSD's auditor, having audited PG&E's accounts, takes no exception to this amount. She states that the amount requested is primarily a result of the difference between forecasted and recorded kWh sales. Specifically, sales were forecasted to be 72.1 billion kWh as compared to actual sales of 61.7 billion kWh for the record period. This represented a 17% difference between recorded and forecasted sales. As a result, the ERAM balancing account reflected an undercollection (p. 3-2, Exhibit 8).

We will adopt the $210.2 million ERAM increase as reasonable; however, since PG&E will shortly be filing a request for an Attrition Increase/Decrease for 1988, and since we wish to avoid multiple rate changes, we will defer inclusion of the ERAM increase in rates at this time. We might mention that PG&E will not be "out-of-pocket" since, unlike the AER, ERAM has a balancing account which accrues interest. Accordingly, PG&E may include the $210.2 million ERAM amount in rates at the time it files its 1988 attrition rate change.

Findings of Fact

1. For purposes of this ECAC/AER forecast period which ends July 31, 1988, there will be no generation from Rancho Seco.

2. For purposes of this ECAC/AER forecast period, Diablo Canyon Units 1 and 2 will achieve a 75% operating cycle capacity factor.

3. For purposes of calculating the IER, the UEG gas rate stipulation, Exhibit 10 adjusted to reflect the underlying volumetric change, should be used with the methodology in PG&E's Exhibit 3, p. 3, Table 1, Case 2.

4. Large thermal QF Projects Nos. 15, 16, 24, and 25 will provide zero generation during the forecast period.

5. A 50/50% split should be used to allocate energy delivered by QFs less than 1 MW in size for purposes of this proceeding.

6. There should be no change to the present 91/9% ECAC/AER split.

7. A 60-day lead time to estimate the reliability requirement of PG&E's fuel oil supply is reasonable.

8. There are certain inconsistencies in the use of definitions by the parties in estimating resulting capacity factors of nuclear power plants. There is a need for consistency in this area to avoid waste of hearing time.

9. For this forecast period, PG&E is entitled to ECAC/AER/ERAM revenue increases on an annualized basis of $56.4 million, $3.5 million, and $210.2 million, respectively.

Conclusions of Law

1. For PG&E's ECAC/AER period August 1, 1987 to July 31, 1988, the resource forecast adopted should be as set forth in this decision.

2. The adopted ECAC/AER/ERAM revenue increases for PG&E should be deferred from inclusion in rates at this time. PG&E may file tariff sheets for inclusion of the AER/ERAM amounts in rates at the time it files its 1988 attrition rate change. The ECAC amount should be included in PG&E's next ECAC proceeding.

3. The adopted resource forecast should be the basis for the production cost modeling in Phase 2 where we will determine PG&E's avoided cost and IER for power delivered to PG&E from QFs.

4. In order to avoid waste of hearing time with regard to definitions related to nuclear power plant operation forecasts, E&C should issue a set of adopted definitions for use in future ECAC proceedings.

O R D E R

IT IS ORDERED that:

1. For Pacific Gas and Electric Company (PG&E), the adopted resource forecast for the period August 1, 1987 to July 31, 1988 is as set forth in Appendix B.

2. PG&E is entitled to revenue increases related to its Energy Cost Adjustment Clause (ECAC), Annual Energy Rate (AER), and Electric Revenue Adjustment Mechanism (ERAM), as set forth in this opinion. However, these amounts shall not be reflected in rates at this time.

3. PG&E is authorized to file revised tariff schedules at the time it files its 1988 attrition rate change to recover in rates the AER/ERAM revenue increases adopted in this opinion. The revised tariff schedules shall comply with General Order 96-A.

This order is effective today.

Dated NOV 13 1987, at San Francisco, California.

STANLEY W. HULETT
President
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

Commissioner Donald Vial, being necessarily absent, did not participate.

9. For this forecast period, PG&E is entitled to ECAC/AER/ERAM revenue increases on an annualized basis of $56.4 million, $3.5 million, and $210.2 million, respectively.

Conclusions of Law

1. For PG&E's ECAC/AER period August 1, 1987 to July 31, 1988, the resource forecast adopted should be as set forth in this decision.

2. The adopted ECAC/AER/ERAM revenue increases for PG&E should be deferred from inclusion in rates at this time. PG&E may file tariff sheets for inclusion of the AER/ERAM amounts in rates at the time it files its 1988 attrition rate change. The ECAC amount should be included in PG&E's next ECAC proceeding.

3. The adopted resource forecast should be the basis for the production cost modeling in Phase 2 where we will determine PG&E's avoided cost and IER for power delivered to PG&E from QFs.

4. The adopted revenue requirement, which includes an estimate of geothermal steam cost, is not a Commission determination of the respective rights and obligations of PG&E or Union under their steam sales contract for the Geysers.

5. In order to avoid waste of hearing time with regard to definitions related to nuclear power plant operation forecasts, E&C should issue a set of adopted definitions for use in future ECAC proceedings.

ORDER

IT IS ORDERED that:

1. For Pacific Gas and Electric Company (PG&E), the adopted resource forecast for the period August 1, 1987 to July 31, 1988 is as set forth in Appendix B.