ALJ/jt

Decision 84 08 118 August 7, 1984

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to adjust its electric rates effective August 1, 1984. (Electric)	Application 84-04-028 (Filed April 6, 1984; amended May 16, 1984)

(See Appendix A for appearances.)

INTERIM OPINION

In this proceeding Pacific Gas and Electric Company (PG&E) seeks to revise its electric rates effective August 1, 1984 under its Electric Cost Adjustment Clause (ECAC), Electric Revenue Adjustment Mechanism (ERAM), and Annual Energy Rate (AER) procedures. This proceeding also encompasses PG&E's annual reasonableness review for both its gas and electric departments.

PG&E's April 6, 1984 filing was revised on May 16, 1984 to reflect later available data. PG&E's revised request is as follows:

ECAC Increase (Including Chevron settlement)	$848.5 million
AER Increase	53.2
ERAM Decrease	84.8
Total Increase	$816.9 million

PG&E also requests a $0.7 million reduction in rates subject to the Steel Surcharge Adjustment Clause (SSAC).

Summary of Decision

This decision authorizes PG&E to increase its electric rates by an average of 15.4% primarily to offset the change to a normal rainfall year from two prior periods of above normal rainfall. Above normal rainfall results in the availability of substantially more than usual low cost hydroelectric power, which is replaced by more expensive natural gas/oil generated electric power in normal rainfall periods.

The decision authorizes the following increases in annual revenues:

	(-000)
ECAC	$697,700
AER	31,669
ERAM	(105,687)
Total	$623,682

( ) = reduction

This decision does not include in the above revenue requirement a provision for $38.5 million in underlift charges resulting from the settlement of a civil suit filed by Chevron USA, Inc. (Chevron) against PG&E concerning a contract for the purchase of low sulphur fuel oil (LSFO). The reasonableness of that settlement agreement will be the subject of further hearings before this Commission.

The authorized additional revenue requirement is spread to each customer class on a System Average Percentage Change (SAPC) basis under which the revenue increase for each customer class is uniform. Within each class, the increase is spread to individual rate schedules on an equal cents per kilowatt-hour (kWh) basis.

Background

The substantial revenue increases sought here stem principally from the change from a year in which there was abundant low cost hydroelectric power available to PG&E from its own resources and from the Pacific Northwest to a near average rainfall year.

It is important to stress that the magnitude of this increase is a direct reflection of the transition from two record hydro years to a period of average precipitation (as of April 1, 1984, PG&E was at approximately 92% of average for the 1983-1984 precipitation period). Present ECAC/AER rates are premised on hydroelectric and purchased power forecasts emanating from the record precipitation winters of 1981-1982 and 1982-1983. These rates are based on the April 1983 hydroelectric potential forecast which exceeds by 53% the April 1984 forecast used by PG&E in this proceeding as the basis for requested rates. The situation is further exacerbated by the fact that precipitation, between January and April 1984, was 50% below normal.

It has been amply demonstrated that, depending upon hydro availability, energy costs on the PG&E system can swing more than one billion dollars in each direction. According to PG&E, these cost variations are caused by the more than 50 million equivalent barrel fluctuation in PG&E fossil fuel requirements between a drought and a very wet year. Indeed, evidence presented in OII 82-09-02, the Commission's ECAC procedures investigation, indicates that if a drought year and a high hydro year occurred back to back, the swing in energy cost could approach \$2 billion (D.83-02-076, Mimeo. pp. 16-18). In recognition of these extreme cost variations, among other reasons, this Commission has adopted ECAC procedures which provide for recovery of additional annual revenues over a twelve-month period. These procedures are applied in this proceeding.

The Proceeding

Public hearing was held before Administrative Law Judge (ALJ) J. W. Mallory during the period June 4 through June 15, 1984. Thirty-four exhibits were received. Toward Utility Rate Normalization (TURN) and California Manufacturers Association (CMA) actively participated throughout the proceeding. CMA also made an affirmative showing. In addition, the California League of Food Processors (Food Processors) presented evidence and recommendations on rate design. The first phase of the proceeding was submitted upon receipt of closing briefs due July 6, 1984. The first phase covered all issues except the May 16, 1984 settlement of the Chevron litigation of facility charges. This issue will be dealt with during the final phase of the proceeding hearings scheduled during the week of August 13, 1984. Additionally, the staff proposed in its Exhibit 8 an incentive structure that would, beginning July 1, 1985, pass through in user rates only 75% of any take-or-pay/minimum bill payments that PG&E might make pursuant to provisions of its gas supply contracts. It was ruled that this proposal not be considered in this proceeding.

Late-filed Exhibit 32 sets forth the PG&E and staff final calculations of the increase in PG&E's ECAC and AER revenue requirement. Late-filed Exhibit 33 sets forth changes in the staff recommended ERAM reduction in view of Decision (D.) 84-05-100 and D.84-05-101 in Application (A.) 82-12-48 (decisions revising the order in PG&E's last general rate proceeding) which decreased PG&E's base revenues to which the ERAM applies. PG&E agrees with the correctness of the base revenue recalculation, but disagrees with its applicability here. As Exhibit 33 also reflects, PG&E otherwise agrees with the staff-developed ERAM decrease. The staff and PG&E recommendations are summarized below:

	PG&E	Staff	Percent Difference
ECAC Increase*	$712.2 Million	$694.9 Million	2.4%
AER Increase	32.7	31.3	4.3
ERAM Decrease	85.3	105.7	24.0
Totals	$659.6 Million	$620.5 Million	6.0%

*Excludes all Chevron settlement effect.

CMA and TURN have proposed additional adjustments not reflected in the above compilation. The unresolved revenue requirement issues will be discussed below.

ECAC Issues

Exhibit 32 contains the respective staff and PG&E ECAC calculations for the 12-month forecast period commencing August 1, 1984 as set forth in the following table:

PACIFIC GAS AND ELECTRIC COMPANY
ENERGY COST ADJUSTMENT CLAUSE
CALCULATION OF CHANGE IN REVENUE REQUIREMENT

Line No.		PG&E $(000)	STAFF $(000)	DIFFERENCE $(000)
	Steam Plants			
1	Gas	$1,419,265	$1,409,259	$10,006
2	Oil-Residual	$25,877	$24,081	$1,796
3	Oil-Distillate	$2,603	$2,603	$0
4	Subtotal-Fossil	$1,447,745	$1,435,943	$11,802
5	Geothermal Steam Plants	$285,674	$285,674	$0
6	Nuclear Steam Plants	$0	$0	$0
7	Purchased Elec. Energy	$727,665	$725,570	$2,095
8	Water for Power	$3,279	$3,279	$0
9	Economy Energy Credit	($63,960)	($63,960)	$0
10	Oil Inventory Carrying Cost	$56,799	$56,799	$0
11	Facility Charges	$0	$0	$0
12	Fuel Oil Underlift Pyxt.	$0	$0	$0
13	Losses/Gains on Sale of Fuel Oil	$11,581	$10,502	$1,079
14	Total Energy Expenses	$2,468,743	$2,453,807	$14,936
15	Less 9% of Energy Expenses(1)	$222,187	$220,843	$1,344
16	Subtotal of Energy Expenses	$2,246,556	$2,232,964	$13,592
17	Excess Oil Inventory Carrying Cost	$70	$64	$6
18	Subtotal	$2,246,626	$2,233,028	$13,598
19	Allocation to CPUC Jurisdictional Sales(2)	$2,193,381	$2,180,105	$13,276
20	Energy Cost Adjustment Estimated as of July 31, 1984 And Adjusted to Provide for Amortization over 12 Months	($95,902)	($99,774)	$ 3,872
21	Subtotal	$2,097,479	$2,080,331	$17,148
22	Adjustment for Franchise Fees and Uncollectible Accounts Expense(3)	$19,653	$19,493	$160
23	Total ECAC Revenue Requirement	$2,117,132	$2,099,824	$17,308
24	Total ECAC Revenue at Present Rates(4)	$1,404,957	$1,404,957	$0
25	CHANGE IN REVENUE REQUIREMENT	$712,175	$694,867	$17,308

(1) Line 13 x .09
(2) Line 17 x .9763
(3) Line 20 x .00937
(4) At rates effective March 30, 1984

Cost of Gas

The difference between staff and PG&E with respect to cost of gas (line 4) results from the use of a different heat rate.[1] PG&E estimated a 0.60% increase in efficiency over historical data, producing a heat rate of 10,754 British Thermal Units (BTu) per kWh, while the staff projected a heat rate 0.74% less than that projected by PG&E. The staff and PG&E used essentially the same historical data to make their projections; however, staff analysis averaged the improvements on a monthly basis; the monthly averages were then annualized and applied to the February 1983-January 1984 generation data to produce the Btu saving separately for 33 operating units. Staff argued that PG&E's heat rate is based on 1982 and 1983 recorded data which fails to take into account an expected improvement from PG&E's increased maintenance efforts. For example, PG&E has spent several million dollars ordering an inventory of turbine components, which will be installed in the forecast period in a significant number of units that are normally used in power production. The staff argued that its adjustment is reasonable because it gives effect to expected improvements in heat rates and should be adopted.

We have continuously encouraged PG&E to improve the efficiency of its aging fossil fuel plants, and some improvements will take place in the forecast year. We believe that the staff projection more accurately portrays the plant heat rates which actually can be achieved in the forecast period and the staff adjustment will be adopted.

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[1] The heat rate measures the efficiency of fuel consumption of fossil fuel generating plants.

Cost of Fuel Oil

Staff proposed a reduction of $1,751,000 in PG&E's estimate of the cost of fuel oil (Line 2) to reflect a lower estimated cost of oil for refinery cogeneration. ($45,000 is an adjustment for the staff's lower heat rate.)

PG&E has three contracts with oil refineries whereby it provides steam to the refineries in exchange for oil. However, under the contracts, PG&E may, and does purchase more oil than is necessary for the steam production. This oil is purchased under the contracts at prices in excess of equivalent present gas costs. PG&E has included this oil in its forecasted burn at formula-derived contract prices. The staff recommends that only the cost of an equivalent amount of gas at the G-55 (boiler fuel) rate be allowed for the forecast period. Staff argued that PG&E has terminated its LSFO contract with Chevron and the staff believes negotiations to more fairly and realistically price the refinery cogeneration oil or to terminate these provisions of these contracts should have taken place and been resolved by the August 1, 1984 commencement of the forecast period.

PG&E asserts that the staff adjustment is based on faulty premises. PG&E states that the fuel pricing mechanisms are contracts which have been approved by the Commission. PG&E contends that the staff witness has misconstrued the pricing and delivery provisions of the contracts, as PG&E cannot elect not to accept fuel from the refinery cogeneration partner for electric generation; therefore, PG&E cannot price the fuel for electric generation different from other oil purchases under contracts with its refinery cogenerators. PG&E also argued that it does not have the option under the contracts to substitute natural gas or some other less expensive fuel for the refinery fuel supplied to generate the minimum electric output specified in the contracts. Each contract will be in effect during the entire forecast period, and PG&E does not have the right to renegotiate the contract provisions. PG&E argued that if the staff adjustment is adopted, it would experience an underrecovery in the AER, even if it should be able to renegotiate the contracts prior to the end of the forecast year.

PG&E asks that we use the present contract fuel prices under the refinery cogeneration agreements in the current ECAC/AER forecast, and review in the next reasonableness proceeding PG&E's efforts to reduce the fuel pricing provisions of its refinery cogeneration agreements. If the utility's actions are unreasonable, an appropriate adjustment can then be made.

We believe that inclusion of the current contract rates in the AER is consistent with our intent in establishing the AER, and in providing for a reasonableness review of fuel decisions. PG&E is placed on notice however that we expect it to make every effort to reduce fuel oil contract prices below the G-55 gas rate applicable to its own boiler fuel uses, and that those efforts will be reviewed in the next reasonableness proceeding. For the purposes of the current forecast, we will use fuel oil prices set out in current refinery cogeneration agreements.

Costs of Energy Purchased
From Qualifying Facilities

PG&E forecasts it will purchase from Qualifying Facilities and cogenerators (QFs) 3,660 gigawatt hours (gWh) of electricity at an average cost of 7.465¢ per kWh. Its forecast is based on its 1983 fourth quarter Cogeneration and Small Power Production Quarterly Report (cogeneration report), which is incorporated in its April 1984 Fuels Outlook. We have authorized and directed PG&E to update the data in this application, as filed, to reflect the April Fuels Outlook.

The staff proposes that the forecasted expense for QF purchases be reduced by $2,094,700 (line 7). The staff argued that PG&E's original and revised QF data do not reflect any price adjustment for certain QFs which have elected in 1984 to sign Standard Offer No. 4. That offer's energy option No. 1 will pay QFs about 0.75¢ kWh less in the forecast period than the other three standard offers, which offers are used by PG&E to price the QF purchases. Cogeneration under Standard Offers Nos. 1, 2, and 3 are priced at an average cost of 70 mills kWh, while additional generation under Standard Offer No. 4 is priced by PG&E at 55 miles kWh.

The staff witness presented in Exhibit 16, a list of 17 QFs which had opted for Standard Offer No. 4, and the adjustments to forecasted purchases from such QFs to effect the lower prices contained in Standard Offer No. 4.

PG&E's witness testified that while PG&E may purchase energy under Standard Offer No. 4 at less than its forecasted price, any such energy cost decrease would be offset by greater costs in other areas, and therefore, assumed that all QF purchases would be at avoided costs. In its pricing, PG&E assumed a $3 per kilowatt (kW) month firm capacity charge, yielding $15 million total capacity payments. PG&E argued that under the terms of the Cogeneration Report, the forecasted capacity payment should have equaled at least $8.50 per kW month, or $40 million during the forecast period. PG&E argued that the staff adjustment should be revised to reflect the higher capacity payments.

PG&E asks that we accept its forecasted QF purchased power costs, and that we not adjust them downward by $2.5 million for the staff adjustment to energy costs or upward by $25 million for the related adjustment to capacity costs. We will accept PG&E's forecasted cost of QF purchases because acceptance of the staff adjustment to QF energy costs also would equitably require an adjustment increasing QF capacity costs.

Geothermal Steam Plant Costs and
Chevron Contract Facility Charges

PG&E and staff were requested by the ALJ to show the calculation of the change in the forecasted ECAC/AER revenue requirement to exclude the Chevron facility charges agreed upon in the settlement for the forecast period. Under its terms, we must approve the settlement to November 1, 1984 or the settlement agreement will not take effect. Deletion of such facility charges affects the charges paid by PG&E to its geothermal suppliers, so that a slight reduction in geothermal steam plant costs in line 5 results. The geothermal steam plant costs will be adjusted upward in the event the settlement is approved in a subsequent order and accrued facility charges are included in ECAC/AER revenue requirement for the balance of the forecast year.

Even though PG&E supplied the information necessary to recalculate the revenue requirement to exclude the Chevron facility charges, it argued in its brief that those charges should be included in ECAC/AER revenue requirement for the full forecast period, as imposition of interest charges on amounts temporarily excluded would not benefit its ratepayers. We do not believe that the facility charges should become part of ECAC/AER revenues until we have had opportunity to review the settlement and determine its reasonableness. Therefore, we will exclude the accrued facility charges in the Chevron settlement until review of the reasonableness of that settlement is concluded.

Price for Northwest Energy

TURN proposes that purchased power costs be adjusted to reflect a lower price for northwest energy purchased in June 1985. TURN suggests in its opening brief that half of the June 1985 northwest energy purchases be priced at the lower 11 mills kWh spill rate rather than the 18.5 mills kWh standard rate for Bonneville Power Administration (BPA) power purchases, resulting in a downward adjustment of nearly $4 million.

TURN's brief states that in this proceeding it is particularly concerned with the company's forecast of the length of time during which the spill rate will be in effect in 1985. PG&E projects 75 days of spill rate energy, beginning in mid-March and continuing through April and May. For June PG&E estimates a price of 19 mills (18.5 mills standard rate plus some guaranteed delivery premium). PG&E expects spill conditions to prevail in June 1985, under normal weather assumptions, but PG&E's witness applied the higher standard rate to June 1985 BPA purchases because of BPA's stated revenue maximization policy, which has been in effect since November 1983. TURN argued that despite that policy, BPA has charged the 11 mills spill rate for the bulk of 1984 when northwest hydro conditions were only 6% above normal, and in prior years during which both above normal and near normal hydro conditions prevailed. TURN also argued that the record shows that Edison and our staff project 91 days of spill rate energy in 1985 in Edison's A.84-02-11, and that spill rate conditions apply to both PG&E and Edison when such conditions are in effect. TURN states that we should reach consistent results in both the Edison and PG&E proceedings on this point.

TURN's brief states that PG&E projects purchases of 1,054 gWh in June 1985; if half of that energy is purchased at the 11 mills spill rate, rather than the 18.5 mills standard rate, the saving would be $3,952,500 (527 gWh times $.0075). TURN urges that this amount be removed from the PG&E and staff purchased power expense estimates.

As staff did not file a closing brief, it does not address TURN's proposal. PG&E, in its closing brief, argued that, while it forecasted spill conditions to prevail in June 1985, its witness priced BPA energy in that period above the spill rate because it believed market conditions will allow BPA to price its energy above the spill rate consistent with BPA's policy to maximize its revenues. PG&E argued that BPA spill rate pricing in June of 1981, 1982, and 1983 is irrelevant because BPA had no authority in those years to charge at a rate other than the spill rate. PG&E's witness explained he expects that BPA will be able to exercise greater market power in June 1985, because spring spill conditions taper off in June concurrently with greater BPA purchases by California utilities because of higher load demands. PG&E argued that 1985 is forecasted to be different from 1984. According to PG&E May 1984 was a month of extraordinary precipitation in the northwest (151% of normal). This abnormal precipitation in May 1984 impeded BPA's ability to control the spill in June 1984 and, therefore, reduced its market power. PG&E contends that no such unusual situation is projected for 1985; for the purposes of the forecast, normal precipitation is predicated for all months.

PG&E further argued that in June 1984 BPA will have additional market power by initiating its intertie access program, which is designed to prevent other northwest utilities from undercutting BPA's prices and sales of energy to California utilities. PG&E argued that, for all the above reasons, June 1984 conditions should not be used to judge what BPA may be able to in June 1985.

PG&E states that Edison's forecast has no bearing on the issues in this proceeding as that forecast period ends May 31, 1985, the month preceding that in which spill energy rates are in dispute.

The adjustment proposed by TURN hinges on whether its reliance on historical conditions or PG&E's projected actions by BPA are correct. Both parties agree that northwest spill conditions will occur in June 1985; the question, then, is how will BPA price that energy. Our analyses of the arguments leads us to believe that conditions have sufficiently changed so that we cannot categorically state that June 1984 conditions will prevail in June 1985 with regard to BPA's pricing of spill energy. Under the circumstances described by PG&E, it is not unreasonable to assume that BPA will excise a higher rate for spill energy in July 1985 than in July 1984, and that PG&E's forecast is just as likely to occur as any other. In the circumstances, we will not adopt TURN's adjustment.

Purchased Power Intertie
Capacity Forecast

CMA's witness proposed that an adjustment be made by adding northwest purchased power to be used by the operations of PG&E's Helms Creek Pumped Storage Plant (Helms) in the forecast period. Helms will use off-peak electric power to pump water into storage; that water will be released to generate electricity during peak usage periods. The least expensive off-peak energy for Helms would be economy energy purchased from the northwest. The ability to make additional northwest purchases is limited by the capacity of the intertie transmission lines between the northwest and California.

PG&E estimated that its intertie will be used at 95% of capacity in the forecast period based on historical usage of the line. CMA presented evidence designed to show that some of the unused capacity resulted from turnbacks of economy energy, and that such turnbacks accounted for about 2.72% of the intertie capacity. It is CMA's position that there will be no need to turn back off-peak economy energy in the forecast period, as that energy will be consumed by Helms.

TURN supports CMA's proposed adjustment. TURN argued that the commercial operation of Helms will minimize intertie curtailment to the degree advocated by CMA. PG&E argued that its rebuttal evidence established the factual errors in that argument. PG&E witness testified that the post 1982 increase of 420 megawatts (MW) of cogeneration offsets Helms to a sufficient degree that some hydro constraint on the intertie will still occur. PG&E argued that other base load capacity (principally geothermal) of 550 MW has been added to PG&E's system since late 1982, which together with cogeneration equals 935 MW, sufficient to offset Helms' power requirements. Its position is that some constraints or backdowns of northwest hydro will continue to occur.

PG&E's witness also testified that the 95% average utilization of the northwest intertie is reasonable in consideration of other constraints, such as scheduled and nonscheduled outages and the effects of loop flow which reduces the nominal capacity of the transmission line.

We have carefully reviewed this proposed adjustment and conclude that it should not be adopted. We recognize that 100% utilization of a major facility cannot be achieved over an extended period because of normal maintenance and forced outages. An estimated 5% reduction from maximum capacity to account for scheduled and unscheduled outages and for loop flow, which varies in magnitude as generation resources and points of consumption change, does not appear unreasonable. Coupled with the fact that PG&E's added generation resources offset Helms' consumption, it is also reasonable to project hydro constraints in the forecast period more or less equal to prior periods. Therefore, it has not been shown that PG&E's estimate of intertie utilization is unreasonable and no additional northwest power purchases should be imputed.

Economy Energy Credit

The economy energy credit (line 9) represents the economy electric energy sales revenue to offset PG&E's cost of producing that energy. Those costs are included in gas costs (line 1). Revenues over that cost figure are retained by PG&E as other operating revenue. The appropriate treatment of economy energy sales is set forth in D.92496 in OII 56, (4 CPUC 2d 693 at 716) as follows:

> "The appropriate treatment of economy energy sales has been an issue in several ECAC proceedings. We have deferred a final decision to this generic proceeding.

"There has been no dispute over the buyer's cost recovery in ECAC. There has been no dispute over the netting out of the seller's fuel expense and the equivalent offsetting revenue. The issue has been the ratemaking treatment of the incremental revenue above the fuel expense and whether it should be included in ECAC or base rates.

"Our disposition is suggested by our discussion of variable wheeling charges. We wish to maximize the incentive for the seller to give it an incentive to make sales that by definition are advantageous to the buyer. This result is achieved by excluding such revenue from ECAC."

Questions were raised by CMA and TURN. PG&E presented Exhibit 29, which responded to CMA's challenge to PG&E's costing of economy energy sales and TURN's questions about a division of revenue between a credit to ECAC and other operating revenues. According to Exhibit 29, the line 9 credit of $64 million is overstated by $5.8 million. The staff and PG&E jointly filed Exhibit 34 in which they agree that no adjustment to the economy energy credit should be made in this proceeding. Exhibit 34 stated as follows:

"PG&E and the CPUC staff jointly agree, based on PG&E's analysis of economy energy sales transaction data for 1982 and 1983, that no adjustment to the ECAC revenue requirements with respect to this balancing account item is needed in this ECAC proceeding. The CPUC staff agrees that PG&E's analysis of economy energy sales reasonably supports this proposal.

"However, PG&E and the CPUC staff agree that PG&E's balancing accounting treatment of economy energy sales transactions appears to have overstated the fuel component of economy energy sales, and therefore overstated the economy energy credit to the ECAC balancing account, based upon a limited sampling of transactions by PG&E. If, in the future, PG&E proposes to correct its 1982 and 1983 economy energy credits recorded in the ECAC balancing account, the CPUC staff reserves the right to audit the supporting basis for that adjustment at the time of the proposal."

In their briefs, CMA and TURN challenge the statements in Exhibit 34.

According to Exhibit 29, the cost of generating a kWh of electricity sold as economy is 61 mills, based on PG&E's G-55 rate of 55¢/therm for gas and heat rate of 12,000 Btu/kWh. The 61 mills kWh is debited to the ECAC balancing account. In accounting for the economy energy sales credit, the marginal cost of gas (37¢/therm) is used at a 10,000 Btu/kWh heat rate, resulting in a credit to the ECAC balancing account of 37 mills kWh. Sales of that energy are made at 41 mills/kWh. The difference of 4 mills between the sales price of 41 mills kWh and the marginal cost of gas of 37 mills kWh is the profit which, under D.92496, PG&E retains. PG&E contends that use of corporate cost of gas (G-55 rate) in economy energy sales is consistent with PG&E's "one-company" fuel cost minimization strategy.

CMA urged in its Exhibit 25, that the marginal cost of gas, rather than PG&E's G-55 rate, be used in the first step of this calculation. CMA argued that the economy energy credit procedures are merely an accounting treatment which transfers funds from PG&E's electric department to its gas department, as the gas used to generate electric is priced at the high G-55 rate, but sales are accounted for at the average cost of gas. CMA also argued that this method of pricing where electricity is sold at 41 mills per kWh, but is charged to the ratepayer at 61 mills, results in a windfall to purchasers of economy energy.

CMA proposed that a reasonable interpretation of the phrase in D.92496 "the netting out of the seller's fuel expense and the equivalent offsetting revenue" is as follows:

1. Price PG&E's gas department sales to its electric department at the marginal cost of gas (37¢/therm).
2. The Gas Adjustment Clause (GAC) balancing account and the ECAC balancing account are credited and debited for the volume of gas used to generate economy energy sales at the marginal cost of gas.

3. The profit (loss) in economy energy sales to other utilities above the marginal cost of gas is retained in base rates.

TURN states that it has consistently supported PG&E's "one-company" fuel policy. TURN stated that it is clear that there is an overall benefit as a result of economy energy sales. TURN argued, however, that the accounting treatment for the economy energy credit creates bizarre results. TURN stated that under that treatment, the gas department gains 41 mills kWh. PG&E's shareholders gain 4 mills kWh, and the electric department loses 24 mills kWh.

TURN pointed out that this is the first decision in which we determine the intent of the D.92496 language quoted above since, up to this time, PG&E estimated no economy energy sales. TURN states that subsequent decisions (D.82-12-105 and D.83-08-048) revising AER and ERAM procedures shed no light on the subject, and the proper accounting for economy energy revenues lies somewhat in a vacuum. TURN suggests that it would be logical and consistent to include the entirety of economy sales revenues in ECAC/AER.

TURN's brief also pointed out a possible conflict of Section B, Clause B.6.b(2) of PG&E's Preliminary Statement to its electric tariff with the procedures described above and Finding 51 of D.92496, which states: "Economy energy sales should be reflected in base rates in order to maximize incentive to sell surplus power." That tariff clause provides that "91 percent of the amount of revenues, if any, billed during the month for the fuel and purchased energy component of intersystem transactions based on incremental or replacement costs" shall be credited to the ECAC balancing account.

The record points up the inconsistencies of the accounting practices associated with economy energy sales. TURN's brief and CMA's testimony and brief explore possible alternates which may provide more reasonable results. Staff accepts current practices. We appreciate the analysis of this problem made by CMA and TURN in this proceeding. It is clear, however, that clarification of the proper accounting treatment of economy sale revenues cannot be accomplished based on the state of the present record. Therefore, we will direct PG&E to file within sixty days a compliance filing in this proceeding detailing a ratemaking proposal for properly identifying and accounting for the profit potential associated with economy sales revenues. To the extent possible, PG&E's filing should address the basic issues raised by CMA and TURN in this proceeding. PG&E's filing shall also address the issue raised in this proceeding of the ambiguity of PG&E's ECAC tariff (Preliminary Statement, Subsection B.6.b(2)) as that issue bears on the appropriate ratemaking treatment of economy sales revenues. Other parties, including staff, shall have 30 days to file written responses to PG&E's compliance filing. At the conclusion of this comment period, we will issue an appropriate further order(s) in an attempt to clarify this issue on a timely basis.

We will accept, for the purposes of this proceeding only, the recommendations of our staff and PG&E in Exhibit 34, with the intent that such procedures be revised by future order, as previously discussed.

Losses on Sale of Fuel Oil

The ECAC balancing account includes a recorded amount of $39,510,941 in fuel oil sales losses. This amount represents 100% of losses recorded during the current record period (February 1983 through August 1984) and also an amount of $4,915,455 recorded in January 1983 (end of the prior record period). This is in accordance with D.82-12-109, December 22, 1982.

In its forecast, PG&E included $11,541,800 in fuel oil sale losses, again 100% of the forecasted amount. This discussion treats oil sales losses both as a forecast issue and as a reasonableness issue.

D.83-08-057 rolled over to this proceeding the proper allocation between shareholders and ratepayers of oil sale losses for the record period involved in that proceeding, set up two optional methods of allocation, and directed PG&E and the staff to develop additional information needed to apply such options which was lacking in the record in that proceeding. The lacking information was the length of the probable holding period of the oil, the future repurchase price of the oil, the proper discount rate, and the proper sales tax adjustment.

No party challenged the reasonableness of the oil sales or the losses on such sales in past periods, nor were the forecasted oil sales and projected losses challenged as their reasonableness. The issues to be decided are the proper allocation of the oil sale losses between ratepayers and shareholders, and the proper carrying charges on the oil sale losses.

PG&E, our staff, and TURN agree that the two options set forth in D.83-08-057 are difficult to apply and achieve conflicting results based on different assumptions as to how long the oil would have remained in storage if not sold, the appropriate discount rate, and the repurchase price of oil. The parties agree that a different method of allocation of fuel oil losses between ratepayers and shareholders is needed, and each party proposed a different approach to that issue.

PG&E's Proposal

In this application as filed, PG&E estimated, based on its January 1984 Fuels Management Outlook, that shareholders would bear $1.23 million to $1.27 million in the past oil losses. In its Exhibit 5, PG&E set forth allocations of oil sale losses in accordance with the methods described in D.83-08-057 and its proposed method of allocating such losses based on its April 1984 Fuels Management Outlook. Using the later data, the exhibit concludes that under any of the three methods shown therein there should be no disallowance to shareholders (i.e., ratepayers should bear all losses), and PG&E should recover 100% of the past and future oil sale losses through ECAC. PG&E argued that its allocation methods reflect the significant carrying cost savings already achieved by ratepayers because of the early sale of excess oil; that, with the increasingly high availability of other less expensive sources of electric generation, the need to hold LSFO for future use has diminished; and that the appropriateness of prior oil sales has been reinforced with time.

Staff Recommendations

The staff recommends that only 91% of the amount of recorded and forecasted oil sale losses be allowed recovery in the ECAC. Therefore, with respect to recorded oil sale losses 9%, or $3,872,000 would be disallowed. (ECAC calculation, line 13.) No portion of this disallowance would be recovered in the AER. (The AER revenue requirement is based upon a 91/9 split based on the ECAC calculation, line 14, total forecasted energy expenses.) With respect to forecasted oil sale losses, 9% or $1,039,000 would be disallowed (ECAC calculation, line 13). Of the remaining 91% or $10,502,000, 91% is allowed ECAC recovery and 9% is disallowed AER recovery.

The staff argued that the discussion on oil sale losses in D.83-08-057 reiterates the Commission's long-standing policy and intention to share the burden of excessive fuel oil purchases between ratepayers and shareholders. The staff states that the Commission further recognized that under certain circumstances sales of oil at a loss, rather than retention in inventory, would be a proper economic choice; however, in so doing, the burden assigned to the ratepayers should not be increased, but should remain at the same level. Staff cited the statement in D.83-08-057 (p. 14) as follows:

> "Cost recovery on fuel oil sale losses will be determined by looking strictly at the ratepayer costs associated with such an action."

The staff testified that it was unable to satisfactorily apply the formula in D.83-08-057. One problem was that the formula measures repurchase cost rather than the increase in average inventory cost in the "sell" option. Another weakness is that the present value of the future burn costs are neglected in the "hold" option. The greatest difficulty encountered by staff with the formula is that it depends on the reliability of various forecasting variables and related assumptions. PG&E was unable to assign a level of reliability to the formula "runs" ~~it developed. The staff~~ rquested PG&E to develop seven different scenarios, changing only the discount rate and the commercial paper rate. The staff witness testified that the sensitivity studies demonstrated that a small deviation in forecast percentages resulted in large variations in potential disallowances, and that this would mean that any forecast values adopted that later prove to have been incorrect, could impose a charge on the ratepayers for an uneconomic fuel oil sale loss, contrary to Commission intent.

Because of these difficulties and the surrounding uncertainty as to the correct values to use in the LSFO sales loss allocation formula, the staff recommends a 91/9% split be applied to the fuel oil sale losses to fairly represent a sharing of loss risk based upon the ECAC/AER ratio. The resulting disallowance from the balancing account as of August 1, 1984, including interest, is $3,872,094. In the forecast period, the disallowance is $1,039,000.

PG&E presented Exhibit 20 in rebuttal to the staff recommendations. It recommended no adjustment for forecasted losses be made because D.83-08-057 only dealt with losses through July 1984. Staff argued that this contention ignores the obvious intention of the Commission and ratemaking consistency that all losses be subject to similar ratemaking principles irrespective of the date of loss.

TURN's Approach

TURN argued that the formulae set forth in D.83-08-057 be considered as "a good idea that didn't work out" because of the varying results obtained in different time frames. TURN stated that if we intend to use the D.83-08-057 formulae, we should use data applicable to either (1) the date the decision to sell the oil was made, or (2) the date in the future when actual results can be obtained. The latter time frame presents difficulties, as the "actual results" can be obtained only if we wait for several years to the time oil in the same quantity is actually burned, possibly in 1994. TURN stated that the second approach results in a complex and cumbersome procedure which leaves the matter unresolved until 1994.

With respect to the other potential option, to base the disallowance on the information and forecasts that existed at the time the decision to sell oil was made, TURN's brief states as follows: For most of the sales, this time frame was January 1983. At that point the balancing account interest rate was 8.51% compared to the 10% assumed in PG&E's analysis. PG&E's Fuels Management Outlook dated January 28, 1983 projected LSFO burns of 3.8 million barrels during the years 1983-86, compared to expected burns of 1.5 million barrels over that period in the utility's current outlook. At that time natural gas curtailment to the power plants was expected to begin in November 1986, versus a forecast of 1992 or 1993 today. Both of these factors would have tended to produce a higher shareholder allocation of the oil sale loss in January 1983, but complete information is not available in this record to perform the entire calculation. TURN urges that if the Commission prefers this date-of-the-decision scenario for calculation of the disallowance, PG&E should be directed to provide the necessary data in the latter phase of hearings in this case.

TURN's brief suggests that an alternative to the above is to apply a flat percentage disallowance to sales losses, such as recommended by the staff. TURN states that although the staff proposal to disallow 9% on $3.9 million falls within the range of disallowances calculated in the sensitivity analysis in Exhibit 17, those analyses are misleading because they only measure changes in two variables (discount rate and commercial paper rate) and do not measure the holding period for oil if it had not been sold.

TURN's brief states that because the variations in the holding period are not measured, all calculations in the record assume PG&E will not have to burn oil except for testing purposes until 1992-93. This assumption assertedly creates a bias in the sensitivity analyses underlying the staff proposal. TURN states that PG&E's witness testified that there is about a 20% probability that fuel oil will be required for other than testing purposes in the winter of 1984-85 and about a 25% probability in 1985-86. TURN argued that it is unlikely, therefore, that PG&E will experience normal conditions over the next eight years under which fuel oil will only be used for test burns and more likely that some fuel oil will be used in place of other fuels. In the latter circumstance, the assumed holding period would be shortened, which would increase the shareholders' allocation of losses.

TURN also argued that the 91/9% split adopted for ECAC/AER has no direct relationship to the ratepayer/shareholder risk on oil sales losses. TURN believes that a 41% allocation to ratepayers and a 59% allocation to shareholders correspond to the limited recovery of carrying costs on economic oil in inventory adopted in D.82-12-109, and that a 50/50 sharing of the risk would correspond to the risk allocation adopted for the target capacity factor at San Onofre Nuclear Generating Station II (SONGS II) in D.83-09-007.

TURN recommends that if the hold/sell allocation formulae in D.83-08-057 are retained, the Commission should either apply the formulae to the information and forecasts that existed at the time PG&E made the decision to sell, or wait until the actual events occur to determine whether ratepayers benefited or suffered because of the sales. If the Commission prefers to discard the formula and apply a flat percentage disallowance, TURN suggests that a 50/50 allocation would be more consistent with the policy originally adopted in D.82-12-109.

Discussion

As explained above none of the parties accept the hold/sell allocation formulae set out in D.83-09-007. We have reviewed the evidence and argument with respect to those allocation methods and conclude that they should not be applied to past or future oil sale losses because the results are different depending on: (1) when the analyses are made, (2) the length of time oil would be held, and (3) the appropriate discount rates are incapable of being forecasted with any certainty.

It is still our intention to shift some of the risk for oil sale losses to shareholders from ratepayers, as announced in prior decisions. As it appears that a formula approach measuring the variables discussed above does not provide reasonable results, a different approach is required. PG&E's proposal results in the ratepayers assuming all the burden for past and projected fuel oil sale losses: thus, PG&E's approach does not meet our criterion that shareholders bear some of the risk. The staff approach will provide a means of sharing the burden of fuel oil sale losses between ratepayers and shareholders in line with our previously announced intent. The staff approach would provide a simple and easily applied method of calculating the allocation of these risks.

The question raised by TURN is whether the 9/91% allocation proposed by staff is reasonable, or whether some different allocation is proper. Risk sharing decisions made by the Commission to this point have been more or less experimental and inexact as no numerical formula has been devised which precisely measures those risk allocations.

We accept for the purpose of this proceeding the 9/91% allocation formula proposed by our staff. The 9% of total fuel oil losses which must be borne by shareholders appears to be reasonable based on the limited information in the record. There are no data in the record to support a greater disallowance as proposed by TURN.

TURN's arguments which would correlate a disallowance to the carrying cost rates approved in an earlier decision are not convincing as carrying costs are a small part of the allocations involved. Similarly, even TURN recognized in its brief that there is no correlation between the target capacity factor of a new nuclear plant and losses on sales of fuel oil.

While we have achieved our announced purpose of allocating fuel oil losses between shareholders and ratepayers for purposes of this proceeding, we still desire further information on the reasonableness of the allocation factors adopted in D.83-08-057. In that decision, we set forth a method of analyzing ratepayer costs which we termed "analogous to PG&E's methodology in Exhibit 6". (D.83-08-057, Mimeo p. 15). We then set forth an illustrative example of this method for application in this proceeding. In view of the manner in which the formulae-approach measuring the variables was applied (in a rigid rather than illustrative manner) by PG&E and staff, and the resultant wide swings in results, the D.83-08-057 approach had to be abandoned in favor of the adoption of the 9/91% allocation proposal. However, we are still interested in using the D.83-08-057 approach, in analyzing fuel oil sales losses in future ECAC proceedings. Thus, we will direct PG&E, staff, and TURN (1) to conduct informal workshops to develop a plan for implementing the D.83-08-057 approach and (2) to file a workshop report outlining this plan in this proceeding by November 1, 1984. It is our intention to have this information available for timely use in PG&E's next ECAC proceeding, and assuming fuel oil sale losses are an issue, we will expect PG&E's application to reflect the workshop plan.

ECAC Balancing Account

The ECAC balancing account (line 20) will be adjusted to give effect to the order in D.84-07-072 dated July 5, 1984 in A.83-03-84 to transfer the overcollection of $544,015 (plus accrued interest of $26,006) in the Kerckhoff 2 Savings Adjustment Account (KSAA) to the ECAC balancing account.

Adopted ECAC Revenue Requirement

Based on the foregoing discussion of contested issues, the adopted ECAC revenue requirement which we find reasonable, is set forth in the table which follows:

Table 1

PACIFIC GAS AND ELECTRIC COMPANY

Energy Cost Adjustment Clause
Calculation of Change in Revenue Requirement

Line No.		Adopted $(000)
	Steam Plants	
1	Gas	$1,409,259
2	Oil-Residual	25,787
3	Oil-Distillate	2,603
4	Subtotal-Fossil	1,437,649
5	Geothermal Steam Plants	285,674
6	Nuclear Steam Plants	0
7	Purchased Elec. Energy	727,665
8	Water for Power	3,279
9	Economy Energy Credit	(63,960)
10	Oil Inventory Carryall Cost	56,799
11	Facility Charges	0
12	Fuel Oil Underlift Pymt.	0
13	Losses/Gains on Sale of Fuel Oil	10,502
14	Total Energy Expenses	2,457,608
15	Less 9% of Energy Expenses (1)	221,185
16	Subtotal of Energy Expenses	2,236,423
17	Excess Oil Inventory Carrying Cost	64
18	Subtotal	2,336,487
19	Allocation to CPUC Jurisdictional Sales (2)	2,183,482
20	Energy Cost Adjustment estimated as of July 31, 1984 and adjusted to provide for amortization over 12 months	(100,344)
21	Subtotal	2,083,138

22	Adjustment for Franchise Fees and Uncollectible Accounts Expense (3)	19,519
23	Total ECAC Revenue Requirement	2,102,657
24	Total ECAC Revenue at Present Rates (4)	1,404,957
25	CHANGE IN REVENUE REQUIREMENT	$ 697,700

(1) Line 14 x .09

(2) Line 18 x .9763

(3) Line 21 x .00937

(4) At rates effective March 30, 1984

AER Issues

The AER differences between PG&E and staff result from different treatment of ECAC issues as discussed under that heading. The impact of Diablo Canyon on fuel costs was not considered in this proceeding. Therefore, we may adjust the AER, if appropriate, to reflect such impacts based on findings made in the Diablo Canyon proceeding (A.84-06-014). The calculation of the AER revenue requirement, after resolution of ECAC issues, is as follows:

Table 2

PACIFIC GAS AND ELECTRIC COMANY
Summary of Annual Energy Rate Revenue Requirement
Test Year Beginning August 1, 1984

$(000)

Line No.	Item	
1	Carrying Cost of Oil Inventory	$ 56,799
2	Est. Fuel & Purchased Power Expenses	2,400,809
3	Total Energy Expenses	2,457,608
4	Nine Percent of Energy Expenses (1)	221,185
5	Allocation to CPUC Jurisdictional Sales (2)	215,943
6	Adjustment for Franchise Fees and Uncollectible Accounts Expense (3)	2,023
7	Total AER Revenue Requirement	217,966
8	Less: AER Revenue at Present Rates	186,297
9	Change in Revenue Requirement	$ 31,669

(1) Line 3 x .09
(2) Line 4 x .9763
(3) Line 5 x .00937

ERAM Issues

Exhibit 33 is a late-filed exhibit jointly filed by PG&E and our staff. Exhibit 33 sets forth the agreed-upon calculation of the ERAM revenues requirement. PG&E and staff concur in an ERAM reduction of $85,340,403. PG&E acquiesced to the staff's proposed offset of bad check revenues of $500,000. Revenues from customer returned checks are now included in base revenues as expenses associated with returned checks are included in authorized general rate case base revenues. This treatment of returned check revenues will be adopted for future general rate proceedings.

Our staff also proposed an additional $20.47 million base revenue reduction to reflect changes to adopted base revenues in PG&E's general rate case (D.83-12-068) ordered in D.84-05-100 and D.84-12-068. PG&E concurs in the amount calculated, but disputes the need for that adjustment and asks that it be deferred.

PG&E has requested rehearing of D.84-05-100 and D.84-05-101 and asks that we defer the changes in base revenues ordered in those decisions until its application is acted upon. The staff argued that decisions on rehearing are final for purposes of judicial review (Public Utilities (PU) Code Section 1756). Although PG&E was not the original applicant for rehearing which led to the two decisions on rehearing, PG&E did not seek a stay of D.84-05-100 and D.84-05-101 in its application for rehearing. The reasons advanced by PG&E are inappropriate. D.84-05-100 and D.84-05-101 are final and the adjustments to base revenues ordered in those decisions should be made here.

The following table sets forth the adopted ERAM revenue requirement for the 12-month period beginning August 1, 1984:

Table 3

Adopted ERAM Revenue Requirement

Modified Authorized Operating Revenues for 1984		$2,452,267,000
Less: Conservation Load Management Refund		(22,996,000)
Modified Adopted Test Year Base Rate Revenues for 1984		$2,429,271,000
Less: Modified Other Operating Revenues		(16,846,000)
Add: Adjustment for S.F. City and County Wheeling		27,000
Less: Transfer of Base Rate Expense to ECAC/AER		
Maintenance and Operating	$(9,079,000)	
Purchased Water	(3,024,000)	
Franchise and Uncollectible	(113,000)	(12,216,000)
Modified Authorized Base Revenue Amount for 12-month Period Beginning August 1, 1984		$2,400,236,000
Less: Total Estimated Revenue at Base Rates for 12-Month Period Beginning August 1, 1984 Inclusive of Returned Check Revenue		(2,444,099,000)
Subtotal		(43,863,000)
Estimated ERAM Balance at July 31, 1984 Inclusive of Return Check Revenues		(61,824,405)
Modified Decrease in Revenue Requirement		$ (105,687,405)

( ) = negative figure

Steel Surcharge Adjustment Clause

The purpose of the Steel Surcharge Adjustment Clause (SSAC) is to collect through rates the shortfall in revenues which result from reduced rates afforded steel producers in California as mandated by Section 742 of the PU Code. The difference between full and reduced rates is charged to the SSAC balancing account and subsequently collected from other commercial/industrial customers.

PG&E requests a decrease of approximately $700,000 to the SSAC balancing account. The requested decrease represents the estimated overcollected balance in the SSAC balancing account at July 31, 1984 plus the forecast difference between the full steel producer and reduced steel producer rates for the 12-month period commencing August 1, 1984. Included in the forecast period difference is estimated revenue to be collected through the SSAC billing factor (SSACBF).

Our staff accountants uncovered no exceptions in its audit of the SSAC balancing account and therefore are of the opinion that the SSAC balancing account is fairly stated.

The PG&E proposal will be adopted.

Revenue Recovery and Rate Design

PG&E has allocated the proposed increased revenue requirement on SAPC with the exception of streetlighting service. PG&E based rates upon the rate design criteria set forth in D.83-12-068 in A.82-12-048 (PG&E's last general rate decision), taking into account the residential baseline rate structure required by § 739 of the PU Code. The staff has reviewed PG&E's allocations and rate design proposals and recommends that they be adopted.

Food Processors believes that the SAPC and rate design guidelines were not correctly applied in this proceeding, because proposed rates are increased by varying percentage amounts. Food Processors believes that SAPC should result in equal percentage changes for each class of customer. It points out that time-of-use (TOU) Schedules A-18, A-21, and A-22 are increased by greater pecentage amounts than residential rates. CMA concurred in Food Processors' concerns about the results of PG&E's rate design proposals. CMA contends that the SAPC should produce a uniform system average percentage change in rates, including each rate within a given schedule.

TURN and PG&E contend that SAPC is a revenue allocation device where the revenue increase (or decrease) for each class is uniform. SAPC, therefore, may produce different percentage changes in energy rates for two different schedules.

TURN concurs in Food Processors and CMA contentions that incorect results come from PG&E's proposal with respect to intra-schedule rate design. PG&E allocated the revenue increase to the major customer classes using the SAPC method and spread the class increase to the various rate schedules within each class using an equal cents/kWh methodology. Within the large light and power class, PG&E's methodology created a higher percentage increase (29.1%) to the A-18 tariff than to the class as a whole (20.2%). TURN argued that D.83-12-068 is unclear whether the Commission meant for SAPC is to be used for intra-class rate as well as for inter-class revenue allocation.

We have reviewed this matter and conclude that PG&E's method of allocating the required revenue increase within each major customer class on a cents/kWh basis is not inconsistent with SAPC and the general rate design criteria adopted in D.83-12-068 for offset proceedings. While higher increases result in the interruptible A-18 schedule than for the other schedules in that class, or the class as a whole, A-18 is an all energy tariff, whereas the specific rates in some other schdules contain an energy component and a demand charge component. The cents/kWh approach produces a larger percentage increase in the published rate when there is no demand component than when such component is included. We will accept PG&E's methodology for the purposes of this proceeding.

Remaining Issues

We have set separate hearings for consideration of the reasonableness issues associated with the Chevron LSFO contract.

Not discussed here are the electric and gas reasonableness studies made by PG&E and our staff and the resulting recommendations.

Those issues will also be addressed in a subsequent decision.

TURN's Participation

PG&E raised legal issues concerning the manner in which TURN participates in proceedings of this nature, and PG&E's ability to present so-called rebuttal testimony anticipating positions which may be taken by TURN in its briefs, but which are unknown at the time of submission. Extensive argument was made by PG&E and TURN on this issue, in both opening and reply briefs.

PG&E essentially argues that its due process rights are violated, and that it is otherwise prejudiced by virtue of the fact that, in its view, TURN is able to delay presenting its affirmative case until it files its opening brief. PG&E further argues that:

> "Basic due process rights include timely notice of the allegations against which the party is asked to defend and a meaningful opportunity to contest those claims. They include the opportunity to cross-examine the sponsor of the alternative position and, through rebuttal testimony, to present additional facts to dispute the facts asserted by the opposing party." (PG&E Reply Brief, p. 4).

PG&E's ultimate position is that "presentation by TURN of its affirmative showing through a witness, as opposed to an opening brief, would restore due process to these proceedings." (PG&E Reply Brief, p. 6).

The spark which ignited the present controversy was TURN's cross-examination of PG&E and staff witnesses on a forecast issue relating to Northwest purchases at spill rates. Although TURN had not explicitly stated its position on this issue in an opening statement, or otherwise, PG&E analyzed TURN's cross-examination, anticipated TURN's arguments, and chose to meet those arguments by presenting supplemental rebuttal testimony (Exhibit 30). This testimony was allowed into the record by the assigned ALJ over TURN's objection. TURN has moved to strike Exhibit 30 in its opening brief.

TURN's position is that PG&E's procedural theory is flawed in that it confuses the roles of evidence and argument. TURN states that lack of funds requires that it use a basic approach relying on data requests, cross-examination, and argument in brief. In TURN's view, the basic issue is whether PG&E is entitled to a right to present rebuttal testimony, or evidence, in response to TURN's arguments. TURN argues:

> "It might perhaps be useful at this point to set forth TURN's understanding of just what is at issue here, since upon careful review the record does seem a bit confusing at times. What TURN objects to is the idea that it can be compelled to reveal in advance of briefing the specific arguments that it intends to raise. Such arguments are classic attorney work products. Similarly, TURN objects to the notion that rebuttal testimony can be offered to refute arguments raised or to be raised in brief. The opportunity for a reply brief provides the company with ample opportunity to answer such arguments, and to point out any facts assumed in TURN's brief that are not part of the evidentiary record. This is the very function of legal argument. Under PG&E's theory it seems that briefing would be reduced to a dry recitation of the record with no room for real argument at all."
>
> "If all that PG&E really wants (and the company appears to want much more) is an indication in advance of briefing as to what subjects will be covered, that desire can easily be accommodated under existing procedures. It is quite common in complex proceedings such as general rate cases for the ALJ to request, at the close of hearings, a statement from the parties of the subjects that they would like to brief. Since the annual ECAC review is becoming almost as complicated as the general case, there is no reason why such a tactic could not be employed. What TURN views as unprecedented and improper, however, is the notion that the applicant is somehow entitled to go back and rebuttress its evidentiary showing once this delineation of issues for briefing

occurs. In essence PG&E is asking TURN: 'What holes do you see in our presentation? Tell us now so we can fix it up before briefing.' It is precisely this third bite at the apple which TURN sees as most inappropriate. For time immemorial the opportunities for redirect following cross, rebuttal to other parties' testimony, and reply to other parties' briefs have been viewed as providing adequate procedural protection for the moving party. PG&E's 'new procedural theory,' the idea that rebuttal should effectively follow briefing, is a deviation from all past procedure and must be rejected.

"With this clarification of the matters really in dispute, it can be seen that PG&E's citations to civil court decisions regarding the scope of discovery are utterly irrelevant. Each of the cited passages refers to attempts to discover 'the factual basis' for a party's contention. If TURN possesses any facts not already in the record which it intends to rely upon in brief, those would presumably be subject to normal discovery. In the typical case, however, TURN is forced to rely entirely upon facts presented by or elicited from the company or perhaps the staff. Since these facts are already matters of record, their discovery by PG&E is clearly not an issue. It is apparent, then, that what PG&E really wants to know is how TURN intends to use those facts in constructing its arguments. None of the cases cited by the utility give it such a broad and intrusive right to probe the minds of its opponent's employees." (TURN Reply Brief, pp. 7-9).

Upon analysis of the arguments presented, it is clear that we cannot force TURN to sponsor witnesses or otherwise dictate its affirmative showing. TURN has chosen the tactical approach of making its case by cross-examination and argument. This is a very difficult tactical approach. Nonetheless, as long as the arguments it advances in its briefs are premised on facts in the record, or otherwise officially noticed, the utility is adequately protected, since we assume it is fully able to marshal the facts in the record (or point to voids in the record and request reopening) to advance counter-arguments.

The issue raised in this proceeding does not require the issuance of an OII; we simply apply longstanding procedural distinctions between evidence and argument to reach our result, based on the briefs and authorities presented by PG&E and TURN.

While we will not strike Exhibit 30, as TURN requests, we do not wish to encourage PG&E in the future to speculate about TURN's position and clutter the record with supplemental "rebuttal" testimony. In the situation at hand, involving Exhibit 30, it would have been preferable, in our view, for PG&E to address the argument raised by TURN through briefs or closing arguments, at the close of evidentiary hearings.

Findings of Fact

1. The adopted resource mix forecasts reasonably represent the availability of purchased power and other generation sources in the forecast and interstate transmission capabilities.

2. The adopted resource mix and related prices are reasonable for the purposes of this proceeding.

3. The adopted fossil fuel heat rate is reasonable in connection with the adopted resource mix and fossil fuel plant operating conditions expected in the forecast year.

4. An operational fuel oil requirement of 7.1 million barrels is reasonable for the forecast period and is adopted for the purposes of this proceeding.

5. PG&E estimates that it will incur losses from the sale of excess fuel oil in the amount of $11,541,800 in the forecast period.

6. PG&E's decision to sell fuel oil and burn natural gas in the forecast period is reasonable. The projected sales and losses on such sales will be economic, and will be reasonable.

7. The use of sell/hold options formulae for allocating recovery of fuel oil sale losses in the historical period between ratepayers and shareholders described in D.83-08-057 were deferred to this proceeding by that decision.

8. The D.83-08-057 hold/sell option formulae could not be used in this proceeding because as applied by PG&E and staff, these formulae produced conflicting results.

9. The substitute method of allocating fuel oil sale losses between shareholders and ratepayers proposed by our staff reaches our previously announced objective of shifting to shareholders some of the burden of such losses.

10. The staff proposal for allocation of such losses is reasonable and should be adopted for this proceeding. That method should be applied to historical fuel oil sale losses and to projected losses for the forecast period. Workshops should enable ~~the parties~~ to reassess the D.83-08-057 formulae for the future.

11. The method employed by PG&E to account in ECAC for economy energy sales to other utilities and the related fuel expense for generation, while conforming with D.92496, produces perplexing results. Such accounting method is adopted for the purposes of this decision, but may be revised, pending analysis of PG&E's compliance filing, and the parties' comments thereto, by further order of this Commission.

12. The increase in the ECAC revenue requirement for the forecast year of $697.700 million set forth in Table 1 is reasonable and is adopted for the purposes of this proceeding.

13. The increase in the AER revenue requirement for the forecast year of $31.669 million set forth in Table 2 is reasonable and is adopted for the purposes of this proceeding.

14. The decrease in the ERAM revenue requirement for the forecast year of $105.687 million is reasonable and should be adopted.

15. The SSAC reduction proposed by PG&E is reasonable and should be adopted.

16. The rate design proposed by PG&E is in accordance with SAPC and other rate design principles for offset proceedings adopted in D.83-12-068 and should be adopted.

Conclusions of Law

1. PG&E should be authorized to recover additional annual revenues over a 12-month period, in accordance with the adopted rate design, as follows.

	(-000)
ECAC	$697,700
AER	31,669
ERAM	(105,687)
	$623,682

2. The SSAC surcharge should be reduced as proposed by PG&E.

3. The changes in rates and charges authorized by this decision are justified and reasonable.

4. While the motion to strike Exhibit 30 will not be granted, PG&E's arguments that it should be allowed to present rebuttal testimony in anticipation of TURN's arguments, or that TURN should be required to sponsor witnesses to make its affirmative case are not persuasive.

5. Consideration of reasonableness review issues, including the reasonablenesss of the Chevron contract settlement, should be deferred to a subsequent order.

6. Since the revision date has passed, this order should be effective today.

INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is authorized to file with this Commission revised tariff schedules for electric rates in accordance with this decision on or after the effective date of this order. The revised tariff schedules shall become effective not earlier than five days after the date of filing, and shall comply with General Order 96-A. The revised schedules shall apply only to services rendered on or after the effective date.

2. Within sixty (60) days of the effective date of this decision PG&E shall file and serve in this proceeding a compliance filing addressing the economy energy sales revenue issues discussed in this opinion. Other parties, including staff, shall have thirty (30) days to file and serve responsive written comments.

3. PG&E, staff, and TURN shall conduct informal workshops to develop a plan for implementing the D.83-08-057 "hold/sell option" approach and shall file in this proceeding a written workshop report on or before November 1, 1984, in accordance with the previous discussion in this interim order.

4. This order decides issues with respect to PG&E's Electric Cost Adjustment Clause, Annual Energy Rate, Electric Revenue Adjustment Mechanism, and Steel Surcharge Adjustment Clause. The proceeding remains open for consideration of issues raised in PG&E's annual reasonableness review, as well as consideration of the ratemaking/accounting issues associated with economy energy sales, and any necessary direction that may be needed in connection with the workshop discussed in Ordering Paragraph 3.

This order is effective today.

Dated August 7, 1984, at San Francisco, California.

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
WILLIAM T. BAGLEY
Commissioners

Commissioner Priscilla C. Grew, being necessarily absent, did not participate.

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

Joseph E. Bodovitz, Executive Director

APPENDIX A

List of Appearances

Applicant: Peter W. Hanschen, Steven F. Greenwald, and William H. Edwards, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Party: David Branchcomb, for Ultrasystems, Inc.; Michael Peter Florio and Jon F. Elliott, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Jane Kumin, Attorney at Law, for Natomas Company; Gerald J. La Fave, Attorney at Law, for California Farm Bureau Federation; Alice Loo, for Bay Area Rapid Transit District; Thomas R. Sparks, for Union Oil Company; Harry K. Winters, for University of California; Ed Yates, for California League of Food Processors; Robert E. Burt, for California Manufacturers Association; William E. Swanson, for Stanford University; Peter N. Osborn, Jeffery E. Jackson, and F. E. John, Attorneys at Law, and T. D. Clarke and Gay A. Phillips, for Southern California Gas Company; Pillsbury, Madison & Sutro, by Russell L. Johnson, Attorney at Law, for Chevron, U.S.A., Inc.; Wayne L. Meek, for Simpson Paper Company; and Donald G. Salow, for Stone & Webster Management Consultants, Inc.;

Commission Staff: Timothy E. Treacy, Attorney at Law, and Jeffrey P. O'Donnell.

(END OF APPENDIX A)