ALJ/vdl H-4

ORIGINAL

Decision 83 08 057 AUG 17 1983

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, 1983.	Application 83-04-19 (Filed April 7, 1983)

(See Appendix A for appearances.)

O P I N I O N

This proceeding encompasses Pacific Gas and Electric Company's (PG&E) August 1, 1983 request to revise its electric rates under its Electric Cost Adjustment Clause (ECAC), Electric Revenue Adjustment Mechanism (ERAM), and Annual Energy Rate (AER) procedures, under Decision (D.) 92496 in Order Instituting Investigation (OII) 56. This proceeding also covers PG&E's annual reasonableness review.

The following compilation shows PG&E's proposed changes in ECAC, ERAM, and AER revenues reflecting amendments made at the hearing to reconcile PG&E's request with the ECAC adjustments made in its last ECAC proceeding (D.83-06-005 dated June 1, 1983 in Application (A.) 83-01-61), and to exclude facility charges and ad valorem taxes on fuel oil inventory, to correct the jurisdictional allocation factor, and to adjust for the operation of the Kerckhoff II hydrogeneration plant (Exhibit 25 and PG&E brief):

Pacific Gas and Electric Company
Amended Rate Increase Request
(+000)

ECAC	$257,016
AER	16,604
ERAM	(82,915)
Total	$190,705

(Red Figure)

Summary of Decision

This decision authorizes PG&E to recover on an annual basis the following increased revenue requirement from its electric customers:

	(+000)
ECAC	$ 27,984
AER	84,569
ERAM	(82,915)
Total	$ 29,638

(Red Figure)

The increased revenue is spread to PG&E's customer classes on an equal cents-per-kilowatt-hour (kWh) basis. The authorized increase in California jurisdictional gross revenues for each class of service for the 12 months beginning August 17, 1983, above rates effective June 1, 1983 are as follows:

Class	Increase Amount (000)	Increase Percent
Residential	$10,009	0.8
Small Light and Power	2,461	0.7
Medium Light and Power	7,014	0.8
Large Light and Power	7,744	0.8
Public Authority	151	0.9
Agricultural	1,848	0.8
Street Lighting	194	0.4
Railway	145	0.9
Interdepartmental	72	0.8
Total	$29,638	0.8

Typical residential bills under present and proposed rates are set forth in Appendix B. The authorized rate increase is expected to raise an average monthly residential bill for usage of 250 kWh by $0.11.

We also find that in the review period PG&E acted reasonably to minimize the fuel costs associated with the supplying of gas and electricity to its customers, except as explained in the body of the decision.

Public Hearings

Public hearings were held in A.83-04-19 before Commissioner Vial and/or Administrative Law Judge (ALJ) Mallory in San Francisco on May 23, 24, 25, 26, and 31, and June 1, 7, 9, and 10, 1983. The matter was submitted on an interim basis subject to the filing of concurrent closing briefs on July 5, 1983. Evidence was presented on behalf of applicant, the Commission staff (staff), California Manufacturers Association (CMA), and by Independent Energy Producers Association and State of California, Department of General Services and Solid Waste Management Board (collectively Energy Producers). Briefs were filed by PG&E, staff, CMA, Towards Utility Rate Normalization (TURN), and Energy Producers.

I. ANNUAL REASONABLENESS REVIEW

PG&E's report on the reasonableness of its gas and electric energy costs for the ten-month period April 1, 1982 through January 31, 1983 is contained in Exhibit 7. The ten-month period represents a transition reporting period (from April 1 - March 31 period to the current February 1 - January 31 period). The report details the decisions made by PG&E during the period. PG&E contends that its energy management in that period was reasonable and prudent measured against conditions known and foreseeable at the time the actions were implemented.

In addition to the extensive evidence produced on other issues, PG&E's Exhibit 7 addresses those reasonableness questions designated in D.82-12-109 as issues in this proceeding, as follows:

1. Outages at Pittsburg 7 steam plant.
2. Reduced capacity factors at the Geysers Units.
3. Reliability criteria.

A. Staff Review - Fuels
<u>Management and Operations</u>

The Fuels and Operations Branch (FOB) staff report is contained in Exhibit 9. The report states that because of limited time available, the review performed by FOB of electric department operations was limited to practices and policies. The staff monitored PG&E's electric operations on a daily basis throughout the record period. For this proceeding FOB also reviewed the following items for reasonableness:

1. Steam plant maintenance and operations.
2. Outages of PG&E generating units.
3. Turndowns of inexpensive power from the Pacific Northwest, and backdowns of the Geysers.
4. Dispatching procedures at PG&E's power control center.
5. Outage of the Pacific Intertie on December 22, 1982.

The review identified no areas where FOB recommended disallowances; due to inherent complexities, the staff's study is continuing in some areas and progress will be reported next year. The FOB staff pointed out several areas where it felt PG&E should further support the reasonableness of its operation.

The FOB review of PG&E's gas department operations showed no evidence of imprudent operations; the staff report states that PG&E purchased reasonable amounts of natural gas from each supply source under the then existing prices and contractual and operational constraints.

B. CMA Presentations

CMA presented evidence on the following reasonableness issues:

1. Pacific Gas Transmission (PGT) takes in excess of the minimum contractual requirement.[1]
2. Possible sales of fuel oil to PG&E's industrial customers.
3. Failure to burn excess fuel oil ("one-company policy").

1. PGT Takes

CMA's witness testified that the contract between PG&E and PGT called for a daily contract quantity (DCQ) of 845 M^2cf. The purchases of Canadian gas by PG&E from PGT were subject to the following minimum purchase obligations:

75% of the DCQ (633.75 M^2cf) each day, and
80% of the DCQ (676 M^2cf per day) each month, and
90% of the DCQ on an annual basis.

PG&E was directed in a prior proceeding to meet the 80% monthly obligation and to accept for ratepayers the costs involved in not meeting the 90% annual obligation.

CMA contends that, contrary to PG&E assertions, PG&E was not limiting its gas purchases from PGT to the minimum monthly take requirement, and that PG&E consistently took more than the amounts necessary to meet the monthly minimum of 676 M^2cf per day (except during the month of December 1982). CMA argued that the daily records introduced in this proceeding shows that on a preponderance of days the takes were made as an accommodation to PGT, which had contracted with Alberta and Southern for a DCQ of 869.79 M^2cf, and

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[1] The ALJ ruled that future revision of PGT contracts was not an issue in the review of reasonableness of past gas department actions. This ruling is affirmed. An appropriate vehicle for that review would be an OII or a complaint.

that the difference between 869.79 and 845 M^2cf was to provide for compressor gas to be used by PGT to move the remainder of its gas through its system. CMA's witness testified that when rates of flow are reduced because of lesser purchases, the reduced flow can be transmitted with less compressor gas. CMA asserts that PG&E took sufficient gas in excess of 676 M^2cf to solve PGT's problem of overcommitment. CMA recommends that the PG&E action be found to be imprudent and $6.488 million be returned to the gas adjustment clause (GAC) balancing account. TURN supports this adjustment.

PG&E argued that CMA and TURN based their challenge to PG&E's Canadian gas takes on the erroneous assumption that neither the PGT-PG&E contract nor the PGT tariff required PG&E to pay for any gas above 80% of the DCQ. PG&E urges that the PG&E-PGT contract cannot be viewed as an isolated contract, but instead must be seen as part of the chain of contracts designed to bring Canadian gas to California through the Alberta-California Pipeline Project. PG&E believes that the PGT-PG&E contract should be analyzed and coordinated with the PGT contract at the US-Canada international border, and the contracts with the Alberta producers which are all links in the arrangement to bring Canadian gas to California.

PG&E states that PGT's FERC tariff recognizes these contractual links and operational needs. Under the PGT tariff the reasonable and necessary operating expenses associated with PGT's purchase of natural gas for sale to PG&E are part of PGT's cost of service for which PG&E is responsible, reflects the integrated nature of the Alberta-California pipeline project, and ties PG&E's payment responsibility to the costs incurred by PGT to obtain gas at the international border for service to PG&E. PG&E argues that included in the reasonable and necessary operating expenses is Account 803 of the Uniform System of Accounts which contains PGT's purchased gas expense. All gas purchased by PGT is for sale to PG&E; therefore, under the tariff, PG&E is responsible for PGT's purchased gas costs at the international border, including the saved compressor fuel volumes. PG&E urges that by acquiring the additional compressor fuel from PGT, PG&E has discharged that responsibility in a reasonable way and has acted prudently.

PG&E contends that based on its staff's investigation, the PGT tariff and the integrated operational and contractual nature of the arrangement to bring Canadian gas to California, the Commission should find that PG&E's takes of PGT gas during the review period were reasonable.

TURN states that CMA has presented a compelling analysis in support of its proposed penalty for purchases of PGT gas in excess of PG&E's contract obligation. TURN would invoke the penalty as a disallowance from the Gas Cost Balancing Account (GCBA) rather than a rate of return penalty proposed by CMA. TURN argued that the burden of proof has not been borne by PG&E as to why its ratepayers should pay for the excess gas taken by PG&E to cover its pipeline subsidiary's admitted excess gas purchases to meet the subsidiary's DCQ.

In its closing brief, CMA states as follows:

> "Assuming that PG&E's statement of the facts about its PGT cost of service contract (brief, pp. 53-54) are correct, it must be concluded that PG&E has no substantial violation of Commission instruction in this regard. Much time would have been saved for all concerned if PG&E had been more adequate in its answer to our original data request on this subject."

Although CMA is now apparently satisfied on this issue and has abandoned its proposed adjustment, TURN still advocates this adjustment to GAC. We conclude that PG&E has borne the burden of proof on this issue and that an adjustment in the amount of $6,488,000 should not be made in the GCBA.

2. <u>Sale of Surplus LSFO</u>

CMA challenged PG&E assertions that it attempted to sell surplus low sulfur fuel oil (LSFO) to industrial users. PG&E

testified that it was restricted in sales of LSFO to potential customers who could take delivery by barge, as PG&E had no truck or rail car loading facilities for LSFO, which requires heating prior to loading and during transportation. CMA attempted to show that truck and rail loading facilities exist which could be used by PG&E. CMA's investigation was perfunctory and inconclusive.

3. Failure to Burn
Excess Fuel Oil

CMA also believes that PG&E should have burned LSFO instead of gas to reduce its excess LSFO in inventory. PG&E's strategy is based on a so-called "one-company" policy under which it looks at the incremental cost of gas to its system, rather than its G-55 rate, in analyzing the costs of selling oil at a loss rather than burning oil. Under the analyses made by PG&E for this proceeding, it is beneficial on a cost basis to PG&E's electric and gas customers, collectively, to sell fuel oil at as much as $13.50 per barrel below the average cost of oil in storage and to burn gas instead. CMA argued that the added costs of fuel oil sales to electric customers be transferred to the Gas Department. The proposed adjustment for the record period is $9.8 million.

TURN supports PG&E's "one-company" policy and states that certain difficulties arise in considering CMA's proposed adjustment. The $9.8 million is calculated by subtracting the price at which each of the four oil sales was made from the $34.288 per barrel G-55 rate equivalent, and then multiplying by the number of barrels in each such sale. TURN argues that this method clearly overstates the proper size of any adjustment. At least one of the sales, APEX #1, was negotiated and completed prior to January 1, 1983, at which time all fuel oil sales losses were part of the AER, and were not includable in the ECAC balancing account. TURN asserts that it is not clear on this record when the second Apex sale was consummated; therefore, it cannot be determined when the losses from that sale were recorded in the Electric Cost Balancing Account (ECBA). (PG&E asserts this sale was consummated in January 1983.) The third Apex sale and the Newhall agreement both took place in 1983, so any losses would be included in ECAC according to D.82-12-109. As later discussed, TURN challenges the reasonableness of those sales and recommends that the losses be disallowed. TURN argued that there is no reason to transfer those dollars if they were not reasonably incurred.

The CMA proposal raises important questions of policy. The issue of interdepartmental equity includes much more than just fuel oil sales losses. If the oil had been stored rather than sold, TURN questions whether a portion of the carrying costs would be assigned to gas customers and, if it were cheaper on a total company basis to burn the oil and reject gas, whether any losses accruing to gas customers would be transferred to the electric side. TURN therefore recommends that this Commission establish a procedural vehicle for addressing the equity question in further hearings.

PG&E asks that we affirm its policy of pursuing the least cost energy strategy for its gas and electric operations on a combined basis (so-called "one-company" policy). It argues that for many years, PG&E has decided whether to buy gas or oil to meet its steam electric plant demands based on the strategy that would produce the least cost overall, within contractual, regulatory, and operational constraints. In this analysis, PG&E does not consider the G-55 rate which the Electric Department has to pay for gas because the G-55 rate represents a transfer price between the two departments and does not change the total least cost strategy for PG&E's utility operations as a whole. PG&E states that CMA acknowledges that its proposed policy of determining fuel acquisition for PG&E's Electric Department independent of its Gas Department by recognizing the G-55 rate as the Electric Department's cost of gas would lead to higher total costs overall. In the review period the policy also would have caused the GCBA to accrue a larger undercollection.

PG&E argued that CMA's concern is not that PG&E has minimized costs; instead, CMA objects that the least cost policy has cost the Electric Department more than a separate policy would. PG&E believes that concern can be better addressed through the allocation of costs from a combined strategy between the Gas and Electric Departments, by setting the G-55 rate to equitably allocate costs between the departments, while still allowing the utility to pursue the overall least cost strategy.

We believe that if PG&E had adopted the fuel strategy recommended by CMA, it would have been subject to criticism because the higher costs to its gas customers and higher overall costs. PG&E's "one-company" fuel strategy has not been shown to be unreasonable, and CMA's proposed adjustment will not be adopted. We will review the CMA proposal in the context of PG&E's general rate proceeding where we concurrently establish rates for both gas and electricity, and where we can evaluate all rate design elements underlying the G-55 rate level.

C. <u>Fuel Oil Sale Losses</u>

TURN argued that PG&E had failed to take into account the Commission's express directive on fuel oil inventory carrying costs in D.82-12-109 when it decided to sell fuel oil out of inventory in early 1983. PG&E's witness testified that the company decided to sell the oil at a $9.25-13 per barrel loss because this was less costly than either burning the oil and rejecting gas ($13.50 per barrel) or continuing to hold the oil in inventory ($18 per barrel for a minimum two-year holding period). TURN contends, however, that the option of continuing to hold the oil would only cost $18 if the carrying cost was calculated according to the utility's pre-tax corporate cost of capital. Prior to D.82-12-109, this would have been appropriate, as ratepayers reimbursed the utility for carrying oil in inventory at that rate. But D.82-12-109 specifically changed the ratemaking treatment of oil inventory to provide for ratepayer reimbursement of only balancing account interest on oil inventory held in excess of the safety stock. At the balancing account interest rate, the option of holding oil in inventory would have been closer to $6 per barrel for a two-year period. which is <u>less</u> than the $9.25-$13 cost of selling the oil at a loss. Therefore, TURN argues, PG&E was imprudent in making the oil sales and needlessly increased ratepayer costs.

PG&E argued that TURN has misrepresented our actions in D.82-12-109. PG&E agrees that the decision authorized PG&E to receive the ECAC interest rate on oil inventory volumes between 5.4 and 11.4 million barrels. Further, PG&E agrees that the decision provides that future oil sale losses would be judged in light of that adopted inventory treatment. However, PG&E argues that it would be unreasonable to construe this to mean that fuel oil sales should be analyzed by the company based on particular inventory "tier" and its associated carrying cost rate. PG&E points out that D.82-01-103 provided for recovery of zero carrying costs above the inventory level of 11.4 million barrels. If PG&E were to use this "zero carrying cost" as a criterion for deciding between holding such inventory or selling it at a loss it would always choose to hold it. This, according to PG&E, would ignore the fact that holding inventory does cause real costs, namely, their coporate cost of capital. Thus, using the inventory carrying cost rates allowable for ratemaking to guide fuel use decisions would distort such decisions and lead to economic fuel sales possibilities being ignored. This would be a perverse outcome of D.82-12-109 since that decision also called on PG&E to reduce its fuel oil inventory. PG&E thus concludes that its losses on fuel oil sales were not imprudent even though they utilized the corporate cost of capital to evaluate the expense associated with the option of continued inventory holding.

We believe that PG&E decisions during the reasonableness review period to sell oil in inventory at a loss were proper economic choices. However, based on the record before us, we believe that PG&E's proposed level of cost recovery on such losses is not reasonable.

It was not the intent of D.82-12-109 to distort PG&E's fuel use decisions. Rather, it was the intent to shift some of the burden of excessive fuel oil purchases to stockholders. That decision found that PG&E had excessive fuel inventory levels that were in part caused by the company's fuel oil contract with Chevron USA, Inc. (Chevron). While not passing judgment on the PG&E-Chevron LSFO contract per se, we did conclude that "we will begin to shift some (contract-related) expenses back to shareholders with the present intention of shifting more expenses in future years." (D.82-12-109, p. 9). A mechanism for explicitly shifting some costs back to the shareholder was the two-tier inventory approach that was adopted. Whereas fuel inventory, like other utility assets, costs the utility its cost of capital to carry,[2] the two-tier inventory scheme only allowed PG&E to recovery carrying costs at a lower ECAC rate for the second, more "excessive" inventory tier. Further, for holding <u>above</u> the second tier, no carrying costs would be allowed in rates. For each tier, any divergence between the carrying costs allowed for rate purposes and the corporate cost of capital would be a cost borne by stockholders. This not only would allocate the burden of excessive inventory holdings more fairly, it would give the utility a strong incentive to reduce its inventory levels.

PG&E correctly points out that it would be at odds with the intent of D.82-12-109 if the company's incentive to reduce fuel oil inventory was seriously weakened because they were forced to utilize

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2 Long-term inventory levels are financed from long-term capital sources. Occasionally, short-term increases in inventory will be financed out of short-term capital sources to meet temporary contingencies. The inventory in question here does not fall into this category, however. It had risen to higher levels only because of a misestimation of long-term meeds by PG&E and an abnormally high hydro year.

the ECAC carrying cost rate or the zero carrying cost rate when analyzing whether to carry oil in inventory or sell it at a loss. The economically efficient choice between such alternatives can only be arrived at if the continued carrying option is evaluated at its higher real cost, the corporate cost of capital.

On the other hand, it would also be unreasonable and at odds with D.82-12-109 if ratepayer exposure to the costs of excessive oil purchases by PG&E were increased merely because PG&E made "cost-saving" sales of its holdings. This is precisely the problem that TURN raises. The problem can be illustrated using TURN's figures listed in its brief regarding the Apex #3 oil sale in January 1983. TURN points out that PG&E could have either sold this oil at a $12.50 per barrel loss or it could continue to carry it in inventory. Assuming a three-year inventory period, this inventory would cost roughly $27 per barrel at the corporate cost of capital to hold or approximately $9 per barrel at the ECAC rate. As noted earlier, the carrying costs allowable in rates would be $9 per barrel with shareholders carrying an $18 per barrel burden ($27-9). TURN argues that because <u>ratepayer</u> costs under the holding option are $9 versus $12.50 per barrel associated with the sale, it was imprudent for PG&E to undertake the sale. PG&E argues that the sale should have been made as the economic cost of the loss on sale. $12.50 per barrel was less than the economic cost of continuing to hold the oil, $27 per barrel.

In this example, PG&E was correct in making the sale but it is unreasonable that ratepayer exposure to the costs of excessive fuel oil purchases be increased from $9 to $12.50 per barrel simply because of the sale. Rather, ratepayer exposure to the burden of this fuel oil should remain at the same level regardless of the use of the oil. Thus, in this example, $9 per barrel is allowable in rates whether the oil is held or sold at a loss. PG&E, however, is able to reduce its stockholder burden from $18 to $3.50 ($12.50 - $9) per barrel by making the proper economic choice and selling the oil.

Our conclusion here follows D.82-12-109, where we stated that:

> "Our reduction in the carrying charges applicable to economic oil inventory beyond operational needs changes the calculations appropriate to determine whether sale of fuel oil at a loss would benefit ratepayers, and therefore whether such losses should be recoverable in rates." (p. 17. emphasis added.)

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

Having decided the proper ratemaking treatment of the fuel oil sale losses in principle, we must address two problems with TURN's analysis which affect our determination of the size of any subsequent fuel oil sale loss disallowance. First, TURN argues that if the oil in question had been held instead of sold, the ratepayer cost would have been measured by the balancing account interest rate. This is incorrect. As Exhibit 7 indicates, all of the oil sales in question were made out of inventory above the 11.4 million barrel level and this oil was being carried totally at stockholder expense with a zero per cent carrying cost for ratepayers. In essence, stockholders were totally at risk for this oil. Our earlier analysis indicated that ratepayer costs should not increase simply because the company made a "cost-saving" oil sale. Since the inventory in question was carried at zero ratepayer expense, this would indicate that ratepayers should not bear any expense for the fuel oil sale loss. Returning to our earlier example, the company would be totally at risk for the oil in question and would reduce its losses from $27 per barrel to $12.50 per barrel by selling it rather than holding it. Ratepayer expense is zero in either case.

If our analysis was to stop here, we would conclude that PG&E should bear the total amount of fuel oil sale losses incurred in three sales made subsequent to D.82-12-109. This would amount to roughly $13 million. There is, however, a second problem with the analysis that was not brought out in TURN's argument. A proper consideration of ratepayer costs under PG&E's hold versus sell decision must take into account the timing of ratepayer costs under either option and also the longer term effect that either option has on future fuel management decisions.

If the oil in question had been held it would have led to ratepayer payment of zero carrying charges over a multiple-year time frame and, possibly, corporate cost of capital charges as the overall inventory dropped to target levels. Eventually, the fuel would have been burned at a future cost of $38.50 per barrel (the original purchase price of oil). The present value of these costs represent the ratepayer cost under the hold option. If the oil were instead sold it would have led to an initial loss which PG&E would have ratepayers recover, and then, eventually oil repurchase at a future oil price when oil was again going to be either held as needed inventory or burned. The present value of these costs represent the ratepayer cost under the sell option. This method of analyzing ratepayer costs is analogous to PG&E's methodology in Exhibit 6.

An illustrative example of this method using the Apex #3 sale, at hypothetical three-year holding period at a zero carrying cost rate, a $30 per barrel 1986 oil price with immediate burn upon repurchase, and a 15% discount rate is as follows:

Ratepayer hold costs = present value [carrying costs] + PV [oil burn 3 years hence]

= 0 + 25.31

= $25.31

Ratepayer sell costs = PV [Loss on sale] + PV [oil repurchase 3 years hence]

= 12.50 + 19.73

= $32.23

The increase in ratepayer costs associated with full ratepayer payment of oil sale losses would, in this example, be $6.92 per barrel. With the sales tax adjustment cited by PG&E in its brief of approximately $2.70 per barrel, the increase would drop to $4.22 per barrel.

This type of comparison of ratepayer costs under the two options represents the proper way to analyze the extent to which PG&E increased ratepayer costs by selling oil rather than holding it, and, therefore, the portion of cost recovery on oil sale losses that should be denied. Unfortunately, we cannot make such a calculation at this time because we lack evidence on this record on the length of the probable holding period of the oil in question, the future repurchase price of the oil under the sell option, the proper discount rate, the proper sales tax adjustment, and particular sales which properly fall within the reasonableness period. We will, therefore, call on the parties to consider this issue more fully in the next reasonableness review with the present intent of denying rate recovery on some portion of oil sale losses at that time.

D. Geysers Power Plant Performance

In last year's reasonableness review concerns were expressed by various parties regarding the declining capacity factors at the Geysers Power Plant. In D.82-12-109 we commented as follows:

> "These issues are in a gray area. Although PG&E has made a substantial showing, there still exists substantial doubt regarding the reasonableness of its operations in these areas. We expect that these issues will be primary issues in PG&E's next reasonableness proceeding." (p. 26.)

The performance of these units did not become a primary issue in this proceeding as we had hoped.

The record shows that the capacity factor at Geysers Unit 15 was only 34.9% in 1982. The contract with the steam supplier for that unit provides for substantial penalties if the supply is insufficient to attain a 50% capacity factor. It is unclear at this time, however, whether the shortfall was the result of inadequate supply or other difficulties. PG&E is still investigating this matter. TURN asks that we direct PG&E to report further on the operations of Geysers Unit 15 in its next reasonableness review, and to hold open to that proceeding a judgment on the reasonableness of 1982 payments to the supplier. This recommendation will be adopted.

Naturally at that time we will expect PG&E to make an affirmative showing with percipient witnesses in support of its claim of the reasonableness of Geysers Unit 15 operations. As stated in D.83-04-089, dated April 20, 1983,

> "This statement conforms to the fundamental principle of public utility regulation that the burden rests heavily upon a utility to prove it is entitled to rate relief. It is not the job of the Commission, its staff, any interested party, or protestant to prove the contrary [citations omitted]. Unless PG&E meets the burden of proving, with clear and convincing evidence, the reasonableness of all the expenses it seeks to have reflected in rate adjustments, those costs will be disallowed [citations omitted]." (mimeo. decision, p. 2.)

E. Further Review of Chevron/PG&E LSFO Contract

This application was submitted on an interim basis so that we may consider at a later time the issue deferred to this proceeding from D.82-12-109 with respect to the reasonableness of including in the AER the facility charge contained in the current Chevron/PG&E LSFO contract.[3]

The record on this issue in the proceeding leading to D.82-12-109 was incorporated into this record by reference. No

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[3] The contract renegotiated in 1981, separated the price for LSFO into two parts: A commodity charge for each barrel of oil purchased and a facility charge which is paid regardless of the volume of oil purchased. The facility charge is intended to compensate Chevron both for its refinery investment and for the reduction in the minimum annual purchase requirement from the prior contract.

additional evidence was adduced. One the initial day of hearing the ALJ ruled that this issue was to be deferred until completion of related civil court litigation. as immediate consideration may jeopardize an early and favorable settlement.

Although receipt of further evidence on this issue was deferred. the parties briefed this issue. TURN points out in its brief that PG&E's LSFO inventory analysis assumes a 60-day lead time to obtain additional LSFO from Chevron. Absent that arrangement, a considerably longer period of 90 to 120 days would be necessary. This would increase the LSFO safety stock inventory requirement by 700,000 to 1 million barrels. TURN states that at PG&E's assumed annual carrying cost of $9 per barrel, the added inventory would cost customers $6.3 to $9 million annually. TURN believes that $6-9 million would be a reasonable price to pay to free ratepayers of the $40 million annual facility charge and 50%-above-market oil price contained in the Chevron LSFO arrangement. TURN asks that we order that any agreement which requires PG&E to pay money to Chevron shall contain the following clause: "This agreement shall not become effective until the California Public Utilities Commission has authorized PG&E to recover in rates all payments provided therein." The general purpose of this proposal is meritorius as there are outer limits to the recovery that will be allowed. One possible option the Commission may choose to explore in the future is the proviso that in future reasonableness review periods purchases under the renegotiated Chevron contract will be compared with purchases of LSFO on the spot market. plus the extra carrying costs for the longer lead times for deliveries of spot purchases. Other options may be equally attractive and these matters should be addressed in the next reasonableness proceeding.

While we will adopt TURN's proposal, we are mindful that the record on this point in the proceeding culminating in D.82-12-109 (which was incorporated into the record by D.83-04-089) may still prove to be valuable to the ultimate resolution of this issue. Therefore, we will incorporate that record into PG&E's next reasonable review proceeding.

F. Guidelines for ECAC Review of Purchases from Qualifying Facilities

Staff Witness Quinley proposed in Exhibit 10 a set of guidelines for the review of the reasonableness of utility purchases of energy and capacity from qualifying facilities (QFs) in PG&E's next reasonableness review proceeding covering the review period of February 1, 1983 through January 31, 1984. The guidelines would apply only to purchases under nonstandard contracts, as purchases under standard offer contracts established under our OIR 2 decisions would be accepted as reasonable and would not be subject to review.

According to the witness, PG&E spent $26.5 million to purchase 432 gigawatt hours (gWh) of energy and 91.3 megawatts (MW) of capacity from cogenerators and small power producers in the current review period, at an average cost of 61.4 mills per kilowatt-hour (kWh). The witness' analysis indicated that these purchases were reasonable in that the average price paid was less than current avoided costs.

The purpose of the guidelines are twofold. The first purpose is to alleviate PG&E's concern about the prudency of entering into nonstandard contracts which call for immediate term payments above avoided costs, particularly when such costs are falling; and PG&E's right to recover in ECAC proceedings purchased power expenses above current avoided costs. The witness stated that, while in the long term, the QF nonstandard contracts will provide savings to ratepayers below avoided costs, there is no present certainty that the long-term benefits will be given consideration in evaluating revenue recovery in ECAC proceedings. The witness indicated that it is also uncertain whether, in the ECAC review process, current avoided cost forecasts would be substituted for the utility's avoided cost forecast current at the time of entry into the QF contracts. The witness' proposed guidelines were designed to address these problems. Secondly, having the proposed guidelines in place assertedly would encourage PG&E and other electric utilities to enter into nonstandard contracts, thus providing more capacity and energy from nontraditional energy sources.

Cross-examination by PG&E developed that some of the current nonstandard contracts with QFs contain either a price change indicator (PCI) or payment tracking account (PTA) mechanism, which is designed to keep ratepayers whole under a range of avoided cost situations. It is PG&E's view that nonstandard QF contracts containing PCI or PTA mechanisms provide adequate protection to ratepayers assuming a QF does not cease production early, precluding the necessity for staff guidelines for use in the next review period.

Dr. Weissenmiller, appearing on behalf of the Energy Producers proposed in Exhibit 16 supplementary guidelines to those proposed by witness Quinley. The primary purpose of the supplementary guidelines is to establish specific nonstandard contract provisions to ensure repayment of overcollections within a specified period (PTA), to place a cap or maximum on overpayments to a QF, and to require security coverage of overpayments. The principals for whom the testimony was adduced are primarily interested in establishing publicly owned QFs who will operate facilities for creating electricity from garbage and other municipal waste materials. Assertedly, establishment of the additional guidelines proposed in Exhibit 16 will aid the public bodies in negotiating nonstandard contracts with PG&E and other electric utilities.

The Energy Producers' proposals overlap the subject matter of our investigations in OIR 2, and the applications which followed, in which initially we have examined long-term and short-term QF standard contract terms. The record in OIR 2 and subsequent proceedings is voluminous, and we would have more information available to us if the proposed guidelines were reviewed in that context. The proposed guidelines for ECAC review of nonstandard QF contracts will not be adopted in this proceeding. Energy Producers should file a request to reopen or modify OIR 2 for the purpose of reviewing the proposed guidelines.

We do not think this, an ECAC proceeding involving one utility, is the place to adopt guidelines for reviewing nonstandard contracts. Once we start adopting guidelines to apply during ECAC review, we will have essentially gone far down the path of approving a new standard offer. The result would be some parameters for nonstandard contracts, and when those are set we would have some loosely defined contract parameters in addition to the specific standard offers already adopted for the three largest electric utilities in D.82-12-120, issued December 30, 1982, in A.82-03-26 et al. Further, such guidelines come too close to constituting "advance approval" of nonstandard contracts, something we have discouraged, except in extraordinary circumstances when a utility has specific concerns about how contract provisions will relate to its ultimate cost allowing for payments (D.82-01-103, OIR-2, issued January 21, 1982, pp. 100-104).

What Quinley and Energy Producers propose is essentially refining, changing, or creating new standard parameters. That should not be done without a carefully developed evidentiary record in a general proceeding; and it should be done on a statewide basis with full input from all concerned. We are hopeful that the negotiating conference held in A.82-04-044 et al., to attempt to have agreement on some standard offers based on long-run avoided costs, will be fruitful and we can put some additional standard offers in place (at least on an interim basis). If that occurs, the pressure to have nonstandard contracts should be mitigated. It is just too early at this juncture, in this proceeding, to adopt the proposed guidelines.

Energy Producers should file a petition to reopen A.82-03-26 et al., or pursue their points in A.82-04-044 et al., for our goal is to have reasonable standard offers which can be extensively used, obviating the need for a plethora of nonstandard contracts.

G. Staff's Proposed Accounting Adjustments

Based on the staff accountants' examination of recorded data in the ECBA in the audit period, the staff audit report (Exhibit 19) recommends several accounting adjustments.

1. Amount of Overcollections

The audit report concluded that the recorded overcollection in the ECAC balancing account is understated. The staff recommends that the July 31, 1983 overcollected balance of $414.8 million estimated by PG&E should be adjusted to $454.9 million, as shown in Table 1 of Exhibit 24. This was later adjusted in late-filed Exhibit 26 to $438,305,000 to reflect the timing of the rate change in PG&E's last ECAC decision. This will be accepted.

2. Booked Fuel Oil Carrying Costs

The staff audit report also recommended that the ECAC balancing account should be adjusted to reflect the removal of fuel oil inventory carrying costs booked into the ECAC balancing account from December 22, 1982 through December 31, 1982. Fuel oil inventory carrying costs above 5.4 million barrels of fuel oil up to 11.4 million barrels were authorized to be recouped through the ECAC balancing account at the commercial paper rate per D.82-12-109, to commence on January 1, 1983, rather than December 22, 1982. The effect of this adjustment is to increase the overcollection at January 31, 1982 by $.37 million. This adjustment was not challenged by PG&E and will be adopted.

3. Capacity Sales to CVP

The staff accounting witness recommended that capacity sales revenues associated with the California Valley Project (CVP) contract in the amount of $25.2 million, plus related interest of $2.7 million through January 31, 1983, be credited to the ECBA. This amount relates to a dispute between PG&E and CVP over the amount CVP owes PG&E for capacity provided. PG&E's billings to CVP reflect PG&E's interpretation of CVP's liability, while CVP has paid a smaller amount which it contends is the proper level. Pending resolution of the dispute, the staff audit report recommends that amounts billed to CVP should be credited to the ECBA on an ongoing basis. PG&E does not object to the proposed treatment. as long as the Commission will allow the company to correct the balancing account to reflect the final resolution of the issue, subject to reasonableness review, so that when the dispute is resolved, PG&E would be allowed to recover reasonable amounts credited. The staff audit recommendation should be adopted, subject to review by the Commission when the dispute between PG&E and CVP is resolved.

4. ECAC Recovery on Excess Oil in Inventory

The staff audit report states that for January 1983, PG&E recorded carrying costs of fuel oil in inventory in its ECAC balancing account at the commercial paper rate on the difference between the actual recorded amount which exceeded the authorized ceiling of 11.4 million barrels in inventory and 5.4 million barrels of fuel oil in inventory which was the authorized amount of fuel oil in inventory for AER recovery in D.82-12-109. The staff believes that PG&E should have recorded in its ECAC balancing account, at the commercial paper rate, fuel oil inventory carrying costs on the difference between the recorded amount of barrels in inventory ceiling (not to exceed 11.4 million barrels) authorized in D.82-12-109, and 5.4 million barrels of fuel oil in inventory commencing January 1, 1983 to properly comply with the intent of that decision. The staff recommends that fuel oil inventory carrying costs be reduced by $.31 million for January 1983. The related interest effect through January 31, 1983 is $3,745. On cross-examination the staff accountant presented several alternatives to the manner in which this adjustment should be calculated.

In its opening brief PG&E advocates the staff alternate method which allows it to record carrying costs based on the difference between actual inventory volumes and the 5.4 million barrels included in AER, subject to a 6.0 million barrel annual cap. TURN states that the annual cap is a cumbersome procedure that will only lead to more difficulties, especially when less than a full year or overlapping annual periods are subject to review. TURN advocates a monthly cap, based on monthly inventory estimates underlying the adopted annual average. TURN argues that neither the staff nor PG&E has correctly applied the two-tier method advocated by it and assertedly adopted in D.82-12-109, and as the ECBA adjustment is greater than the $310,000 advocated by the staff, PG&E should adjust its ECBA calculation of oil inventory carrying costs for January 1983 and subsequent months to conform to TURN's methodology and present such calculations in its next ECAC annual review.

We believe the record is sufficient to decide this issue without carrying it forward to the next ECAC annual review. We will correct the January 1983 recorded carrying cost of fuel oil in inventory in the manner originally proposed by the staff. As we treat the carrying costs on fuel oil differently in this decision (as discussed later) no further adjustments in the ECBA are necessary.

II. ECAC ISSUES

A. Resource Mix Forecast

PG&E and our staff presented separate estimates of the resource mix for the electric sales forecasted for the period

August 1, 1983 through July 31, 1984. These estimates served as the bases for PG&E and our staff calculations of the change in revenue requirements for ECAC and AER. PG&E's estimates were accepted by the staff except for power from hydroelectric generation resources.[4] The parties stressed the importance of accurate forecasting because a greater portion of fuel costs are transferred to AER (as discussed later) and, thus, are exposed to over- or undercollection. The undercollections of the AER portion of fuel costs are unrecoverable by the utility and the overcollections provide an incentive to the utility, subject to the related cap on earnings. We cannot simply accept the utility's forecast as we have in the past, but must carefully evaluate the estimated fuel use in the forecast period.

1. PG&E Hydro Resources

During the course of the hearing, the estimate of hydroelectric power available from PG&E hydro plants and from purchased power hydrogeneration sources located within northern California were revised to reflect the April 1, 1983 snow survey. The effect of using April 1 rather than the March 1 data contained in the application was to increase the forecasted amounts of available hydroelectric power. Both PG&E and the staff based their estimates for the 1983 portion of the forecast period on the April 1 survey, and the 1984 portion of the forecast period on historical precipitation data.

Under cross-examination, but not as a part of his direct testimony, PG&E's witness testified that PG&E expects a carryover into 1984 of about the equivalent of 483 gWh of hydroelectrical generation and that PG&E would store this water for use in the 1984 summer peak usage months of July, August, and September. In other words, 1/3 (or 161 gWh) of such carryover hydroelectric power should be added to the forecast for July 1984 since August and September are

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4 The greater availability of hydroelectric power from PG&E generation and in the form of purchased power in the staff forecast replaced an equivalent amount of natural gas steam plant generation.

beyond the forecast period. At the request of the ALJ, our staff revised its forecast to include the additional 161 gWh (Exhibit 26). PG&E supports this treatment as it is in accord with its basic argument that it is in the best interest of it and its ratepayers to use the carryover for peaking power during the summer months when its system peaks occur.

TURN argued that the entire carryover should be included in the forecast year. The first reason advanced by TURN is that the evidence introduced in PG&E's general rate increase proceeding showed that the utility's avoided costs are higher in winter months than during summer months; therefore, it would be prudent to use the carryover in the early months of 1984. TURN also argued that PG&E's hydroelectric power forecast is seriously flawed. PG&E's forecast was developed on a "current outlook" basis using the latest snow survey for the forecast months of August through December 1983. However, for the forecast months of January through July 1984, PG&E's forecast assumed average hydro production based on historical data. The use of "normal" or "average" hydro production for the January through July portion of the forecast period produces a discontinuity as shown in the monthly projections in the following table:

PG&E Hydroelectric Power Forecast

Year	Month	gWh
1983	August	1401.1
	September	1256.0
	October	1236.1
	November	1329.1
	December	1364.8
1984	January	925.9
	February	940.7
	March	1066.8
	April	1123.7
	May	1223.7
	June	1085.3
	July	1163.7
Total for AER Forecast Period		14116.8

We have serious qualms about PG&E's forecasting methodology. Specifically this record contains no explanation of the rationale for terminating the "current outlook" on December 31, 1983 and assuming normal hydro conditions thereafter. We see no reason why PG&E cannot produce a 12-month forecast based on current conditions, especially when the record indicates that other entities, such as CVP, have the ability to perform a 12-month, rather than 8-month, current outlook. Such a forecast would greatly assist our staff and intervenors in gaining a meaningful understanding of these important issues. Such understanding is crucial in view of the greater portion of PG&E's forecasted fuel costs now includable in the AER, and thus not subject to balancing account treatment. With this increased AER, greater forecasting precision is essential to ensure fairness to both PG&E and its ratepayers.

In view of these concerns, we conclude that PG&E's forecasted use of carryover hydro cannot be adopted. We are not persuaded by this record that PG&E will not use carryover hydro prior to July 1984 to meet peak summer demand. While we decline to include the entire carryover in the forecast year, we are persuaded that it is a reasonable judgment in view of the manner in which this issue developed to include two-thirds, or 322 gWh, of the carryover hydro in the forecast period. We find reasonable and adopt for purposes of this proceeding the staff forecast of PG&E hydroelectric power of 14,116.8 gWh adjusted by the addition for carryover into 1984 of water in storage in an amount equivalent to 322 gWh for a total of 14,438.8 gWh.

2. Purchased Power Volumes

The greatest difference between the PG&E and staff estimates is in purchased power. PG&E estimates 21,955 gWh at an average price of 2.72 cents per kWh; the staff estimates 23,609 gWh at an average price of 2.5394 cents per kWh, which includes certain adjustments suggested by TURN. TURN and CMA support the staff's estimate of volume and price. PG&E and the staff used different methods to forecast purchased power resources. PG&E based its forecast on separate analyses of the different components. By far the greatest amount of purchased power is generated by hydroelectric resources in 1983, but reflects historical average availability in 1984. The PG&E witness testified that PG&E expected large amounts of economy energy to be available from Pacific Northwest hydrogeneration sources through the end of July 1983 in the form of "spill" energy.[5] No provision is made in PG&E's forecast for the additional purchased power which may be available because of the heavy precipitation in the last winter period. On the other hand, the staff has taken this factor into account in its revised tables in late-filed Exhibit 26.

Evidence concerning rainfall and climatic factors was presented by CMA to support the staff's forecasts of hydroelectric power available in 1984 from PG&E and Northwest resources. It is CMA's contention that the weather conditions prevalent during the 1981-82 and 1982-83 winter periods will also likely occur during the 1983-84 winter period both in California and in the Pacific Northwest.

PG&E presented evidence and argument in support of its forecasting methods and in opposition to those used by the staff. PG&E argued that we should accept PG&E's estimate of irrigation district's hydrogeneration as more reliable as it is based on the snow surveys, while the staff has included the power purchased from irrigation districts with all other purchased power. PG&E also opposed the staff's method of forecasting total purchased power using linear regression on a time basis. PG&E argues that there is no theoretical basis for relating total purchased power with time, especially since much of it is precipation-related.

[5] Spill energy is priced lower than other forms of economy energy because it results from the generation of electricity from water which cannot be stored behind dams because the storage is full, and thus, must be spilled whether or not electricity is generated.

PG&E's estimate ignores factors tempering its reliance on a rolling average of five years. These factors include additional installed Bonneville Power Administration (BPA) capacity of 3,900 MW in 1982; additional Northwest generation and storage in 1982; reduced Northwest loads in 1983 over 1982; and increases in intertie capacity over the five-year period. Moreover, while PG&E's own hydro estimate has increased some 20% from its February to April 1983 outlook, its Northwest purchased power estimate remains unchanged.

The staff estimate of purchased power, while not ideal, is the best available on this record because it gives fuller consideration to the expected availability of hydroelectric power in the second part of the forecast year. On the whole, the staff estimate produces more reasonable results than PG&E's estimate of purchased power.

As pointed out in PG&E's brief, the adjustment in staff Exhibit 26 for reduced CVP loads of 366 gWh should be eliminated because this adjustment was already included in PG&E's estimate adopted by the staff. Staff concurs in this change in its forecast.

3. Purchased Power Prices

PG&E and the staff prepared their estimates of purchased power prices in a manner similar to the development of purchased power volumes. PG&E priced out each source separately, while the staff witness used his aggregate trending method to develop unit prices. The staff witness believed that variances in individual purchased power sources would balance so that his methodology was reasonable. With respect to Northwest power prices, the witness testified:

"Q By using ten years of historical data with the first segment of the years having the lower price for the Northwest power than the later years, aren't you also tending to bring down the price of Northwest power?

"A I don't think so.

By using linear regression I fitted a trend line through these data points and the trend line reflects the sum total of all the different pricing changes that have occurred over this ten-year period."

PG&E presented the rebuttal testimony of a statistician to challenge the staff witness's regression analysis. She was unaware of PG&E's methodology and could not testify that PG&E's method was any better than that of the staff.

The CMA witness testified as to the difficulty of forecasting Northwest volumes and prices and that, in view of climatological trends, the staff estimate was conservative.

We believe that both the staff and PG&E forecast of energy prices are conservative considering recent prices and availability of economy energy.

The adopted purchased power forecast and prices are set forth in Table 1.

TABLE 1

Pacific Gas and Electric Company
Purchased Power Forecast
August 1, 1983 through July 31, 1984

Year	Received Megawatt-Hours (Net)	Cost of Energy M$	Cost of Energy Cent/kWh
1973	10,418,084	$ 44,831	0.430
1974	17,241,832	66,904	0.388
1975	16,287,367	106,469	0.654
1976	13,111,599	147,455	1.125
1977	9,792,447	235,528	2.405
1978	15,018,166	142,943	0.952
1979	11,536,777	158,166	1.371
1980	15,180,904	211,319	1.392
1981	17,316,411	575,353	3.323
1982	26,144,333	401,818	1.537
Est 83/84	20,187,600		2.575

Adjustment for estimated favorable 1983 hydro conditions:

Results of Regression Analysis	20,188
Less PG&E purchases from Hyatt-Thermalito	(1,168)
Plus Irrigation District 1983 additional hydrogeneration	1,197
Plus CVP-USBR additional 1983 hydrogeneration	1,231
Plus SMUD additional 1983 hydrogeneration	143
Plus additional Pacific Northwest purchases	1,652
Purchased Power Estimate Expense	23,243 gWh
23,243 gWh x $.02575 kWh =	$598,507,000
Less Irrig. Dist. O&M Excluded from ECAC	8,400,000
Total	$590,107,000

Average Price
without O&M Payments: $590,107,000/23,243 = 2.5389 cent/kWh

4. Conventional Fossil Plant Heat Rate

The following table from PG&E's Exhibit 7, page 3-35, shows conventional fossil fuel plant heat rates and other data for the years 1977 through 1982:

	1977	1978	1979	1980	1981	1982
Billion kWh	42.8	29.8	36.5	29.2	32.5	19.7
Heat Rate Btu/kWh	10,391	10,273	10,452	10,630	10,745	10,912
Capacity Factor*	67.4	47.1	57.7	46.2	51.4	31.8
Gas Million EB*	36.4	21.0	36.1	33.8	47.0	33.6
Oil Million EB**	34.7	28.1	25.0	15.9	8.9	0.8

*The ratio of recorded production (Kwh) to possible production.

**Equivalent barrels.

The data clearly shows that heat rates have been steadily increasing since 1978. PG&E claims this is due to good hydro conditions (Exhibit 7, page 3-34). While good hydro conditions apparently are a contributing factor, they are not the only factor. Hydro conditions have not steadily improved since 1978. Staff originally used the 1982 recorded heat rate in estimating fuel expenses, on the theory that the forecast year would be similar to calendar year 1982, but then accepted PG&E's estimate in late-filed Exhibit 26 after questioning by TURN on the subject.

The quantities we are adopting for hydroelectric generation and purchased power are considerably less than for calendar year 1982. Thus we don't believe it appropriate to use the recorded 1982 heat rate. We are concerned with the continuing upward trend in heat rates. PG&E's estimated heat rate of 10,809 Btu/kWh for the forecast period would reverse the upward trend, if it actually occurs. That heat rate will be adopted as we expect PG&E to devote sufficient resources to operation of its electric steam plant system to achieve a heat rate at least as good as the adopted forecast period heat rate.

We find the staff adjusted resource mix to be reasonable for the purposes of this proceeding, as shown in Table 2. We will reexamine the staff forecasting method for future proceedings on a case-by-case basis.

TABLE 2

Pacific Gas and Electric Company
Adopted Resource Mix Estimate
For Forecast Period
August 1, 1983 through July 31, 1984

Source of Power	Gigawatt Hours	Heat Rate (Btu/kWh)	Fuel Required (Billions of Btus) Gas	Oil
PG&E Hydroelectric	14,439	-	-	-
Purchased Power	23,243	-	-	-
Geothermal	7,417	-	-	-
Combustion Turbines	43	13,000	-	599
Refinery Cogeneration	254	12,886	-	3,273
Conventional Steam Plants-Oil Test Burns	423	10,813	-	4,574
Subtotal	45,819			
Conventional Steam Plants-Remainder	16,767	10,809	181,235	-
Total Electric Energy Requirement	62,586	-	-	-
Totals				
Gas			181,235	
Oil - Residual				7,847
Oil - Distillate				559

B. ECAC Treatment of Chevron Facility Charges

PG&E's original ECAC revenue requirement included $42,662,000 of facility charge payments to Chevron in the forecast period, as well as certain estimated payments in its July 31, 1983 balancing account figure. The total amount involved is $52,788,000. As previously indicated, PG&E currently is not making such payments pending outcome of negotiations with Chevron. Staff accountants recommend exclusion of these amounts from PG&E's ECAC current revenue requirements.

D.82-12-109 directed that PG&E accumulate Chevron facility charges in a subaccount of the ECBA for later rate treatment. PG&E stated in its brief that its primary proposal is to continue to accumulate all Chevron facility charges in the ECBA subaccount for later regulatory review and recovery. PG&E asks that, pending further review of Chevron contract, the present ECBA subaccount for facility charges should be continued. We concur with this proposal. The facility charges will continue to be accounted for in a subaccount of the ECBA; and facility charges will be deleted from the historical and forecast period ECAC revenue requirements.

TURN asks that we indicate to PG&E that the adopted ratemaking treatment for facility charges does not guarantee that PG&E will recover all, or any portion, of the payments actually made to Chevron. TURN believes such language is necessary in order to emphasize that any payments to Chevron will receive careful scrutiny by the Commission. In support of its request, TURN argued that PG&E's economic analysis of its fuel oil requirements in this proceeding makes the assumption that LSFO purchases in late 1983 would come from Chevron at a price of $35.20 per barrel. Purchases in late 1984 are projected to cost $37.70 per barrel. This compares with PG&E's assumed current LSFO sales price in the spot market of $24 per barrel. Underlying the future LSFO cost is PG&E's assumption that it would buy any required LSFO from Chevron at a price over $11 per barrel in excess of what it could sell it for. TURN asserts that it is not reasonable for PG&E to pay almost 50% above the market price for fuel. We conclude that PG&E should be placed on notice that facility charges actually incurred will not automatically be recovered through ECAC procedures, even though ECBA accounting for such charges is approved.

C. Ad Valorem Taxes on
Oil Inventory

PG&E proposed in its application that ad valorem taxes on oil inventory be removed from its general rate case and be placed in its ECAC/AER which is consistent with PG&E's proposal in OII 82-04-02. The staff recommended removal of such ad valorem taxes from ECAC/AER. In its brief PG&E asks we follow our decision in OII 82-04-02 with respect to this issue. In that proceeding, the ad valorem taxes on oil inventory are excluded from ECAC/AER and included in base rates.

D. Calculation of Change in
ECAC Revenue Requirement

Table 3 sets forth the adopted calculation of the changes in the ECAC revenue requirement.

TABLE 3

Energy Cost Adjustment Clause
Calculation of Change in Revenue Requirement

Revision Date: August 1, 1983
Forecast Period: Twelve Months Beginning August 1, 1983

Line No.	Item	Estimated Quantity (6)	Estimated Price (7)	$(000)
	Fossil Fueled Plants			
1	Gas	181,235	$5.3541	$ 970,350
2	Oil-Residual	7,847	5.9105	46,380
3	Oil-Distillate	559	5.4472	3,045
4	Subtotal-Fossil	189,641		1,019,775
5	Geothermal Steam Plants	7,417	3.890¢	288,521
6	Nuclear Steam Plants	-	-	-
7	Purchased Electric Energy (1)	23,243	2.589¢	590,107
8	Economy Energy Credit			(30,750)
9	Subtotal			1,867,653
10	Plus: Oil Inventory Carrying Cost (8)			65,086
11	Subtotal			1,932,739
12	Less: 9% of Energy Expenses (2)			173,947
13	Subtotal: 91% of Energy Expenses			1,758,792
14	Allocation to CPUC Jurisdictional Sales (3)			1,731,883
15	Energy Cost Adjustment Account Balance, Estimated as of July 31, 1983, and Adjusted to Provide for Amortization over 12 months			(438,305)
16	Subtotal			1,293,578
17	Adjustment for Franchise Fees and Uncollectible Accounts Expense (4)			10,258
18	Total ECAC Revenue Requirement			1,303,836
19	Total ECAC Revenue at Present Rates (5)			1,275,852
20	Change in Revenue Requirement			27,984 ✓

(1) Excludes operation and maintenance payments related to certain energy purchase contracts.
(2) Line 11 x .09 ✓
(3) Line 13 x .9847
(4) Line 16 x 0.00793.
(5) At rates effective June 15, 1983.
(6) In billions of Btu or gigawatt-hours.
(7) In dollars per million Btu or cents per kilowatt-hour.

The adopted forecast period carrying cost of oil in inventory is set forth in Table 4.

TABLE 4

Pacific Gas and Electric Company
Carrying Cost of Oil Inventory

Line No.	Item	
1	Authorized Oil Inventory Level	7,900,000 Bbl.
		M$
2	Value of Oil in Inventory (Line 1 x $38.90)	$307,310
3	Return and Income Taxes	$65,086

III. AER ISSUES

A. Background

The purpose of the AER is to recover in rates fuel-related costs which are not given balancing account treatment. The AER is determined by forecasting reasonable costs for the 12-month period beginning August 1, 1983.

In D.83-12-109 we established for the forecast period ending July 31, 1983 a minimum operational fuel oil inventory of 5.4 million barrels which is included in AER as equivalent to rate base. The carrying charges on the AER minimum operational fuel oil inventory are computed at the current authorized rate of return. The carrying costs of an additional fuel oil inventory not needed for operational purposes, but economic to hold, were included in ECAC at the lower interest rate applicable to the ECAC balancing account. PG&E was placed on notice in that decision that in ensuing years it would be our intention to reduce the allowable inventory toward the operational requirement level and that it would be to PG&E's advantage for it to propose to implement a floating inventory mechanism.

B. OII 82-04-02 Investigation

OII 82-04-02 is a generic proceeding dealing with fuel procurement and fuel use policies of electric utilities. One of the principal issues in OII 82-04-02 is the appropriate allocation of fuel-related expenses for rate recovery between the AER and ECAC. Related issues considered in OII 82-04-02 which affect this proceeding are: (1) the appropriate interest rate(s) to use in calculating fuel inventory carrying costs, and (2) the cap on AER earnings variations which should be adopted.[6]

C. Operational Fuel Oil Requirement and Carrying Charges

PG&E points out in Exhibit 6 that its projected minimum fuel oil inventory requirements are made up of three basic components. The first is a year-round inventory amount of five million barrels which is needed to ensure system reliability in the face of basic contingencies such as locational gas curtailments, transmission outages, and oil delivery problems. The second is a monthly inventory requirement which is greater than or equal to five million barrels which depends on seasonal contingencies such as abnormal dry year conditions which increase the need for thermal resources, or abnormally cold winter conditions which increase high priority gas usage and decrease the amount of gas available for electric generation. This seasonal inventory requirement peaks in December, when the uncertainty about winter heating requirements and rainfall levels is greatest.

The first two components of the fuel inventory requirement represent a safety stock necessary to insure against system uncertainties. A third component of inventory arises when it is more economical to hold inventory at the December peak levels throughout the year rather than selling off the inventory after December and buying it up again in the following autumn. This component can increase the inventory requirements in the months other than December, thereby raising the yearly average.

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[6] In D.82-12-105 issued December 22, 1982, we revised the AER/ECAC allocation for Southern California Edison Company (Edison) to 10% for AER and 90% for ECAC. We placed a cap on resulting earnings variations of 160 basis points on pre-tax equity earnings.

PG&E's proposed inventory requirement for the forecast year, 7,939,000 million barrels, is derived in using the aforementioned three components of monthly residual fuel oil inventory and, in addition, adding 120,000 barrels of distillate fuel safety stock.

TABLE 5

Pacific Gas and Electric Company
Proposed Low Sulfur
Fuel Oil Inventory Requirements
(Thousand Barrels)

Month	End of Month Safety Stock	Beginning of Month Operational Requirement	Forecast Fuel Oil Burn	End of Month Operational Requirement
1983				
July	5,000	8,213	30	8,183
August	5,000	8,183	3	8,180
September	5,000	8,180	0	8,180
October	5,100	8,180	180	8,000
November	7,100	8,000	0	8,000
December	8,000	8,000	0	8,000
1984				
January	6,800	8,000	150	7,850
February	6,100	7,850	150	7,700
March	5,300	7,700	150	7,550
April	5,000	7,550	20	7,530
May	5,000	7,530	20	7,510
June	5,000	7,510	20	7,490
July	5,000	7,490	0	7,490
Average	5,700			7,819

Staff does not contest the overall fuel oil requirements. However, in staff's view the safety stock level of 5.7 million barrels of LSFO and 0.12 million barrels of distillate equates to the "minimum fuel oil requirement to meet operating needs" adopted in D.82-12-109. Therefore, following that decision, the safety stock requirement of 5.8 million barrels would be recovered in the AER at the current authorized rate of return, while the additional 2.1 million barrels of inventory requirement in excess of the safety stock would be recovered in ECAC at the current balancing account rate. PG&E argues that the entire amount should be carried at the authorized rate of return.

We will adopt 7,939,000 barrels as a reasonable operational fuel oil requirement for the forecast year. As the inventory analysis that it is based on did not explicitly include demand uncertainties or the possibility of Diablo Canyon not being on line during the forecast year, we consider it to be a relatively conservative estimate.

Following today's decision in OII 82-04-02, 9% of this inventory amount will be placed in the AER where it will be carried at the authorized rate of return and 91% of this inventory will be placed in ECAC where it will be carried at the earned rate of return. Inventory levels in excess of the adopted amount will be carried at the three-month commercial paper rate, as provided for in our decision in OII 82-04-02.

D. Estimated Expense for Facilities Charges and Underlift Payments

Facilities charges and underlift payments were discussed under a separate heading. As indicated in that discussion, no facilities charges or underlift payments have actually been made, and separate ECAC accounting treatment has been provided for the Chevron facilities charges, if any, accruing in the forecast period. Therefore, no amounts should be included for facilities charges or underlift payments.

E. Gains and Losses From Sales of Fuel Oil

No gains or losses from the sale of fuel oil are estimated for the forecast period.

F. AER Percentage

Under current procedures, PG&E fuel-related expenses are allocated on the basis of 2% to AER and 98% to ECAC. As noted above, today's decision in OII 82-04-02 allocated 9% of all forecasted fuel and fuel-related expenses to AER and 91% to ECAC for PG&E. The AER is subject to a cap of 140 basis points.

G. Change in AER Revenue Requirement For Forecast Year

The following table sets forth the change in the AER revenue requirement for the forecast year based on the foregoing discussion.

TABLE 6

Pacific Gas and Electric Company
Annual Energy Rate
Calculation of Change in Revenue Requirement

Line No.	Item	M$
1	Carying Cost of Oil Inventory	$ 65,086
2	Est. Fuel & Purchased Power Expenses	1,867,653
3	Subtotal	1,932,739
4	Nine Percent of Energy Expenses*	173,947
5	Allocation to CPUC Jurisdictional Sales**	171,285
6	Adj. for Franchise Fees & Uncollectible Accounts Expense***	1,358
7	Total AER Revenue Requirement	172,643
8	Less: AER Revenue Authorized in Decision 82-12-109	88,074
9	Change in Revenue Requirement	84,569

*Line 3 x .09

**Line 4 x .9847

***Line 5 x .00793

IV. ERAM

A. ERAM Revenue Requirement

PG&E's ERAM request is based on D.82-12-113, D.82-12-055, and D.82-12-056 concerning the calculation of ERAM revenues. Staff auditors have reviewed PG&E's calculations and are in agreement with the ERAM revenue requirement. No other party objects. We will adopt

PG&E's proposed ERAM decrease of $82,915,000 as shown in the following table:

TABLE 7

Pacific Gas and Electric Company
Derivation of the Change in Revenue Requirement for the Electric Revenue Adjustment Mechanism
(+000)

Base Revenue Amount for Twelve-Month Period Beginning August 1983	$2,188,930
ERAM Balance Estimated as of July 31, 1983	(14,709)
Total Revenue Requirement	$2,174,221
Less: Revenue at Base Rates	2,257,136
Change in Revenue Requirement	$ (82,915)

(Red Figure)

B. Preliminary Statement

The staff accountant testified that a clarification to PG&E's preliminary statement is required to Part E, No. 6 (a)(2) (Cal PUC Sheet 7582-E). The statement "The amount of Electric Department revenue from all applicable sales billed during the month at Base Rates:" should be changed to "The amount of Electric Department revenue for services rendered during the month at Base Rates:" The witness stated that this change reflects a clarification of the Commission's intention of the operations of ERAM. No one opposed this recommendation and it will be adopted.

V. RATE DESIGN

In D.82-12-113 dated December 22, 1982, on rehearing of PG&E rate design issues, we established the following procedure for treating offset revenue changes:

> "We prefer that the rate design portions of offset proceeding be noncontroversial. The methodology to be applied to revenue changes which take place before the next general rate case will be on a equal ¢/kWh basis."

PG&E's proposals comply with this requirement. The specific rate structures are (1) residential rates retain a 30% differential between tiers in effective rates and a Tier I rate approximately equal to 80% of the system average rate (SAR); (2) Schedule Nos. AS-18 and AS-223 are changed to reflect the new SAR; and (3) time-of-use schedules maintain the existing ratios between the on-peak, off-peak, and the partial peak effective rates. The proposed rate structures are reasonable. No party took exception to PG&E's proposed rate design. It is reasonable and will be adopted.

VI. TURN's Notice of Intent to Claim Compensation

TURN filed its Notice of Intent to Claim Compensation under Rule 76.23 of the Commission's Rules of Practice and Procedure on June 22, 1983.

Rule 76.23 specifies that a Notice of Intent must set forth the following three items of information:

> "(a) A showing that, but for the ability to receive compensation under these rules, participation or intervention in the proceeding may be a <u>significant financial hardship</u> for such participant. ***. If the Commission has determined that the participant has met its burden of showing financial hardship previously in the same calendar year, participant shall make reference to that decision by number to satisfy this requirement. (Emphasis added.)
>
> "(b) In every case, a specific budget for the participant shall be filed showing the <u>total</u> compensation which the participant believes it may be entitled to, the basis for such estimate, and the extent of financial commitment to the participation. ***. (Emphasis added.)
>
> "(c) A statement of the nature and extent of planned participation in the proceeding as far as it is possible to set it out when the Notice of Intent to Claim Compensation is filed."

In D.83-05-048, issued during this calendar year (May 18, 1983), we found that TURN had established its financial hardship; therefore by making specific reference to D.83-05-048 in its Notice of Intent to Claim Compensation, TURN has satisfied the requirement of Rule 76.23(a).

TURN submitted a budget of $15,500 in compliance with Rule 76.23(b). TURN also indicated that, if the Commission determines here that TURN has made a substantial contribution, it may request that a multiplier of 1.5 be applied to the budgeted amounts claimed, as discussed in D.83-04-017. This topic will be further addressed by TURN in any compensation filing ultimately submitted by it. With the application of the multiplier, TURN's total request would be approximately $23,000.

Rule 76.23(c) requires that a statement of the nature and extent of planned participation be filed with the Notice of Intent. TURN states that it conducted extensive prehearing discovery and attended virtually all of the hearings. The major issues addressed by TURN included hydroelectric and purchased power estimates and the economics of fuel oil sale losses which, with other issues, are analyzed in TURN's brief.

TURN has complied with the provisions of Rule 76.23(a), (b), and (c), and has established its eligibility for compensation in this proceeding.

Certain procedural issues were raised by PG&E in its Reponse to TURN's Notice of Intent, filed July 5, 1983. PG&E asserts in its Response that TURN's Notice of Intent was filed well after evidentiary hearings had begun and ended, thereby triggering Rule 76.31, which provides in relevant part:

> "(a) A participant who has not requested a finding of eligibility for compensation under Rule 76.23 may make such a request after evidentiary hearings have begun. Such request shall not be granted unless good

> cause for the late request is shown and unless the requirements of Rule 76.23 are met and unless the participant can demonstrate that, absent participation by the participant, an important issue has not or will not be adequately considered in the proceeding."

PG&E claims that TURN has not shown good cause for its late request, as required by Rule 76.31(a), and that TURN's request was not filed within five days after its appearance, as required by Rule 76.31(b). Further PG&E asks the Commission to determine the applicability of Rule 76.31 to TURN's request.

Our rules clearly contemplate the filing of Notices of Intent at three separate intervals during the pendency of Commission proceedings. Two of these intervals are covered by Rule 76.23 which specifies that such Notices are to be filed either before commencement, or after completion, of evidentiary hearings. In the third situation, under Rule 76.31, a participant may make a request for a finding of eligibility for compensation after evidentiary hearings have begun. In such a situation, the logistical problems of considering such a motion while hearings are ongoing, militate in favor of the requirement of a good cause showing. Such logistical problems are not present when a Notice is filed before commencement, or after completion, of evidentiary hearings, and in those situations, the good cause showing is not required.

TURN's Notice was filed, not during the pendency of evidentiary hearings, but after those hearings were completed. Thus Rule 76.31 is inapplicable to TURN's filing.

While TURN has complied with Rule 76.23, we reserve a determination whether TURN has made a substantial contribution to the proceeding pending review of further appropriate filings made under Rules 76.26, et seq.

In its brief staff pointed out the many difficulties it faced in analyzing and presenting its case in this proceeding in view of limitations on time and resources. It is crucial that we allocate sufficient staff resources to obtain a comprehensive record in fuel offset proceedings where the issues are complex and the rate impact is substantial. At the same time the resources of intervenors such as TURN, if carefully directed, become increasingly important to the outcome.

VII. FINDINGS OF FACT

A. Reasonableness Issues

1. PGT takes of natural gas in excess of the minimum contractual requirement were to cover the reasonable and necessary operating expenses associated with PGT's purchase of natural gas for sale to PG&E; therefore, the takes in excess of the minimum monthly requirement were not imprudent during the review period.

2. It has not been shown that any of PG&E's customers which have the capability to burn LSFO also have the capability of receiving barge shipments, or that PG&E could have arranged through terminal operators to move LSFO by motor carriers; therefore, it has not been shown that PG&E was imprudent by not attempting to sell excess fuel oil to its customers during the review period.

3. PG&E's least cost energy strategy under which it decides whether to buy gas or fuel oil to meet its electric steam plant fuel demands based on the least overall cost to both its gas and electric customers was reasonable during the review period.

4. PG&E's decision during the review period to burn natural gas in lieu of LSFO and to sell such oil at a loss represents a proper economic choice.

5. It is not reasonable for cost recovery from ratepayers on fuel oil sale losses during the review period to be higher than what ratepayer costs would have been if the oil had been held, using the carrying cost rates adopted in D.82-12-109.

6. The present record does not allow determination of the proper level of ratepayer costs associated with fuel oil sale losses during the review period.

7. The capacity factor of Geysers Unit 15 of 34.9% in 1982 was substantially below other Geysers Units and below a reasonable level. PG&E's contract with its steam supplier for that unit provides penalties if the steam supply is insufficient to attain a 50% capacity factor. The record in this proceeding is insufficient to determine whether the low capacity factor at Geysers Unit 15 was the result of inadequate steam supplies or for some other reason.

8. Review of PG&E's LSFO contract with Chevron was carried over to this proceeding from the last annual review proceeding (D.82-12-109). Contract negotiations between PG&E and Chevron are still under way and will not be concluded in the near future. The reasonableness of the provisions of the Chevron contract, including the facility and underlift charges, cannot be determined until the contract provisions are finalized.

B. <u>Accounting Adjustments</u>

1. The staff's estimate of the overcollection in the ECBA as of July 31, 1983 of $459.9 million is reasonable and should be adopted.

2. The ECBA should be adjusted $.37 million to reflect the removal of fuel oil inventory carrying costs booked to the ECBA from December 22, 1982 through December 31, 1982, as the authorization for procedure did not become effective until January 1, 1983.

3. Revenues for capacity sales to CVP of $25.2 million plus interest of $2.7 million through January 31, 1983 should be credited to ECBA, and subsequent CVP capacity sales revenue should be credited to ECBA on an ongoing basis. These charges should be reviewed when the dispute between CVP and PG&E concerning the appropriate level is resolved.

4. Except as indicated in the prior findings, PG&E acted reasonably in the review period of April 1, 1982 through January 31, 1983 to minimize the energy costs associated with the supplying of gas and electricity to its customers.

C. ECAC/AER Issues

1. The resource mix forecasts of the staff more reasonably reflect the potential availability of hydroelectric power in the forecast period than the PG&E forecast.

2. The staff resource mix forecast for PG&E hydro should be adjusted to add the carryover into 1984 of the equivalent of 322 gWh of hydro energy, and the staff resource mix forecast for purchased power should be adjusted to reverse a staff adjustment of 366 gWh to PG&E's estimate of hydro power purchased from CVP.

3. The staff resource mix and related prices, adjusted as indicated in the prior finding, are reasonable for the purposes of this proceeding.

4. A fossil fuel heat rate of 10,809 Btu/kWh (Table 1) is reasonable in connection with the resource mix adopted in the prior finding.

5. PG&E should continue to accumulate Chevron facility charges in a subaccount of the ECBA for later rate treatment, as ordered in D.82-12-109.

6. In accordance with findings made today in a separate decision issued in OII 82-04-02, ad valorem taxes on oil inventory will continue to be included in base rates.

7. The staff's proposed guidelines for ECAC review of purchases from QFs and Energy Producers' related proposals overlap the subject matter of our investigations in OIR 2 and related proceedings. The proposals for evaluation of purchases of energy and capacity from QFs are premature and should not be adopted.

8. An operational fuel oil requirement of 7.9 million barrels is reasonable for the forecast period and is adopted for the purpose of this proceeding.

9. Carrying costs on the adopted operational fuel oil requirement should be recovered in accordance with the findings on this issue set forth in the decision issued today on OII 82-04-02.

10. No facility or underlift charges, and no gains or losses from sales of fuel oil, are estimated for the forecast period.

11. Fuel related expenses, including carrying costs on the adopted operational fuel oil requirement, shall be recovered in ECAC and AER in accordance with 91%/9% split and related cap on earnings adopted in the decision issued in OII 82-04-02.

12. The adopted fuel related expenses, including carrying costs on the operational fuel oil requirement, and the related ECAC and AER revenue requirements for the forecast year set forth in Tables 3, 4, and 6 are reasonable for the purposes of this proceeding.

13. A 12-month period to amortize the ECBA is reasonable.

D. <u>ERAM Issues</u>

1. The calculation of the ERAM revenue requirement for the forecast year in Table 7 is reasonable and is adopted for the purposes of this proceeding.

2. Part E, No. 6(a)(2) of PG&E's Preliminary Statement should be revised to show that revenue for services rendered during the month at base rates, rather than amounts billed, should be recorded against the ERAM account.

3. Prospective filings and procedures should be consistent with the Commission's decision in OII 82-04-02 regarding the application of ERAM to AER.

E. <u>Other Issues</u>

1. The rate design proposed by PG&E is in accordance with the requirements of D.82-12-113 and is reasonable for the purposes of this proceeding.

2. The revenue changes authorized by this order should be recovered over a 12-month period.

3. TURN, in filing its intent to claim compensation, has complied with Rules 76.23(a), (b), and (c) of the Commission's Rules of Practice and Procedure.

VII. 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	$104,715
AER	7,839
ERAM	(82,915)
Total	29,639

(Red Figure)

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

3. PG&E should be placed on notice that the fuel related operations of Geysers Unit 15 during the April 1, 1982 - January 31, 1983 review period and thereafter will be scrutinized in the next annual review to determine whether a penalty should be imposed for the low capacity factor of that unit, and to determine whether the low capacity factor was the result of an inadequate fuel supply.

4. PG&E should be placed on notice that fuel oil sale losses incurred during the present review period will be scrutinized in the next reasonableness review to determine a disallowance consistent with our findings herein.

5. PG&E should be placed on notice that the disputed revenues booked in the ECBA for capacity sales to CVP will be subject to further review when that dispute is settled and will not automatically be recovered simply because they were actually expended and accounted for in the ECBA.

6. PG&E should be placed on notice that the ratemaking treatment under which it accumulates Chevron facility charges in a ECBA subaccount does not guarantee that it will recover all, or any portion, of the payments actually made to Chevron. The record developed to date (see D.82-12-109) should be incorporated into PG&E's next reasonableness review.

7. Further consideration of the staff's proposed guidelines for ECAC review of QF purchases, and Energy Producers' related proposals, should receive consideration in the context of OIR 2 and related applications if appropriate petitions to reopen or modify are filed.

8. A ruling on whether TURN has made a major contribution to this proceeding in order to support its claim for compensation under Rule 76.23 should be made after receipt of further filings under Rule 76.26 et seq.

9. PG&E should be directed to amend its Preliminary Statement in accordance with the above findings.

10. Since the revision date is passed this order should be effective today.

O R D E R

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 schedule shall become effective not earlier than August 17, 1983, and shall comply with General Order 96-A. The revised schedules shall apply only to service rendered on or after their effective date.

2. PG&E shall amend its Preliminary Statement on or before August 17, 1983 as indicated in the opinion.

3. PG&E shall comply with the Commission's decision in OII 82-04-02 regarding the application of ERAM to the AER in prospective filings.

This order is effective today.

Dated August 17, 1983, at San Francisco, California.

I concur in part and dissent in part.

/s/ PRISCILLA C. GREW
Commissioner

VICTOR CALVO
PRISCILLA C. GREW
DONALD VIAL
WILLIAM T. BAGLEY
Commissioners

Commissioner Leonard M. Grimes, Jr., 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, Shirley A. Woo, and Steven F. Greenwald, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: William E. Swanson, for Stanford University; Michael Peter Florio, Attorney at Law, Robert Spertus, and Sylvia M. Siegel, for Toward Utility Rate Normalization (TURN); Jane S. Kumin, Attorney at Law, for Natomas Company; Antone S. Bulich, Jr. and Allen R. Crown, Attorneys at Law, for California Farm Bureau Federation; Robert M. Loch, Thomas D. Clarke, and Nancy I. Day, for Southern California Gas Company; Leonard Snaider, Attorney at Law, for City and County of San Francisco; Harry K. Winters, for the University of California (Berkeley); Edward John Reeve, for Simpson Paper Company; Roy Alper and Dan Richards, Attorneys at Law, and Jan Hamrin, for Independent Energy Producers Association; Dr. Robert Weisenmiller, for Independent Power Corporation; Gordon E. Davis, William H. Booth, and Richard C. Harper, Attorneys at Law, and Robert E. Burt, for California Manufacturers Association; Matthew Brady, Richard Owen Baish, and Malcolm T. Duncan, Attorneys at Law, for El Paso Natural Gas Company; Philip A. Stohr, Attorney at Law, for General Motors Corporation; and Ronald C. Peterson, Attorney at Law, for Four Corners Pipeline Company.

Commission Staff: Timothy E. Treacy, Attorney at Law, and Raymond Charvez.

APPENDIX B

Residential Bill Comparison

Monthly Usage	Present Bills	New Bills
240 kWh	$12.30	$12.41
500	29.62	29.90
1,000	72.10	72.80

(END OF APPENDIX B)

APPENDIX C

Customer Class	Present Average Effective Rates (¢/kWh)	Adopted Average Effective Rates (¢/kWh)	% Increase
Residential	6.404	6.457	0.8
Small Light and Power	7.717	7.770	0.7
Medium Light and Power	7.021	7.074	0.8
Large Light and Power	6.530	6.583	0.8
Public Authority	6.056	6.109	0.9
Agricultural	6.914	6.967	0.8
Street Lighting	14.337	14.390	0.4
Railway	6.155	6.208	0.9
Interdepartmental	6.897	6.950	0.8

(END OF APPENDIX C)

PRISCILLA C. GREW, Commissioner, Dissenting in part:

I dissent on three findings made in today's decision which rules on PG&E's annual reasonableness review. Those findings concern (1) outages at Pittsburg 7; (2) decreasing capacity factors at the Geysers exclusive of Unit 15; and (3) purchase of gas from Pacific Gas Transmission in excess of minimum monthly take requirements. In my view, the record and PUC staff analysis were insufficient for me to determine whether or not PG&E acted reasonably in these three matters.

In addition, I think the decision should have ruled on the proposal by the California Manufacturers Association (CMA) and Toward Utility Rate Normalization (TURN) that the Commission order an investigation of Canadian natural gas purchases including high take-or-pay requirements. Rather than ignoring this request, the decision should have stated whether or not the request is granted or denied, and the reasons for that determination.

Pittsburg 7 and Geysers Powerplants

In the previous reasonableness review for PG&E, the Commission stated:

> "The testimony of PG&E shows that there were indeed substantial outages at Pittsburg 7 and decreasing capacity factors at the Geysers... These issues are in a gray area. Although PG&E has made a substantial showing, there still exists substantial doubt regarding the reasonableness of its operations in these areas. We expect those issues will be primary issues in PG&E's next reasonableness proceeding." (Decision 82-12-109 mimeo pp. 25a-26)

In its report, PUC staff did not address these 1981 outages at issue for Pittsburg 7; instead staff reviewed 1982 outages only at Geysers Unit 4 and Contra Costa Unit 5, and recommended no disallowances. Today's decision does not mention Pittsburg 7. As "substantial doubt regarding the reasonableness" of Pittsburg 7 operations existed as of the last reasonableness review, I cannot make an affirmative finding reversing that view in the absence of staff analysis.

Today's decision also makes an implicit finding of reasonableness for all Geysers units except Unit 15. It defers to a future proceeding questions raised by TURN concerning Unit 15. However, Unit 15 represents only about 5 percent of the total installed Geysers field capacity. PUC staff presented no analysis of the reasonableness of declining capacity factors at the Geysers field or assessment of the fuel cost consequences of this decline. In the absence of such evaluations, I cannot make an affirmative finding of reasonableness for all units at the field exclusive of Unit 15.

PGT Purchases

CMA initially proposed that PG&E be found imprudent in taking gas above the minimum monthly requirement from Pacific Gas Transmission (PGT), and that it be penalized $6.488 million. TURN supported this adjustment. In its closing brief, CMA revised its position "assuming that PG&E's statement of the facts about its PGT cost of service contract are correct."

Today's decision states,

> Although CMA is now apparently satisfied on this issue and has abandoned its proposed adjustment, TURN still advocates this adjustment to GAC. We conclude that PG&E has borne the burden of proof on this issue and that an adjustment in the amount of $6,488,000 should not be made in the GCBA.

The Commission's decision gives the impression that this $6.488 million purchase is found reasonable primarily because CMA withdrew its original objection. On the basis of the record, I am unable to determine whether this $6.488 million purchase was reasonable. It would have been desirable for our staff to have offered a perspective on the arguments of parties on this contested issue.

Priscilla C. Grew

PRISCILLA C. GREW, Commissioner

August 17, 1983
San Francisco, California

Summary of Decision

This decision authorizes PG&E to recover on an annual basis the following increased revenue requirement from its electric customers:

	(+000)
ECAC	$104,715
AER	7,839
ERAM	(82,915)
Total	$ 29,639

(Red Figure)

The increased revenue is spread to PG&E's customer classes on an equal cents-per-kilowatt-hour (KWh) basis. The authorized increase in California jurisdictional gross revenues for each class of service for the 12 months beginning August 17, 1983, above rates effective June 1, 1983 are as follows:

Class	Increase Amount (000)	Increase Percent
Residential	$10,010	0.8
Small Light and Power	2,461	0.7
Medium Light and Power	7,014	0.8
Large Light and Power	7,744	0.8
Public Authority	151	0.9
Agricultural	1,848	0.8
Street Lighting	194	0.4
Railway	145	0.9
Interdepartmental	72	0.8
Total	$29,639	0.8

Typical residential bills under present and proposed rates are set forth in Appendix B. The authorized rate increase is expected to raise an average monthly residential bill for usage of 250 kWh by $0.14.

We also find that in the review period PG&E acted reasonably to minimize the fuel costs associated with the supplying of gas and electricity to its customers, except as explained in the body of the decision.

Public Hearings

Public hearings were held in A.93-04-19 before Commissioner Vial and/or Administrative Law Judge (ALJ) Mallory in San Francisco on May 23, 24, 25, 26, and 31, and June 1, 7, 9, and 10, 1983. The matter was submitted on an interim basis subject to the filing of concurrent closing briefs on July 5, 1983. Evidence was presented on behalf of applicant, the Commission staff (staff), California Manufacturers Association (CMA), and by Independent Energy Producers Association and State of California, Department of General Services and Solid Waste Management Board (collectively Energy Producers). Briefs were filed by PG&E, staff, CMA, Towards Utility Rate Normalization (TURN), and Energy Producers.

I. ANNUAL REASONABLENESS REVIEW

PG&E's report on the reasonableness of its gas and electric energy costs for the ten-month period April 1, 1982 through January 31, 1983 is contained in Exhibit 7. The ten-month period represents a transition reporting period (from April 1 - March 31 period to the current February 1 - January 31 period). The report details the decisions made by PG&E during the period. PG&E contends that its energy management in that period was reasonable and prudent measured against conditions known and foreseeable at the time the actions were implemented.

that the difference between 676 and 845 M^2cf was to provide for compressor gas to be used by PGT to move the remainder of its gas through its system. CMA's witness testified that when rates of flow are reduced because of lesser purchases, the reduced flow can be transmitted with less compressor gas. CMA asserts that PG&E took sufficient gas in excess of 676 M^2cf to solve PGT's problem of overcommitment. CMA recommends that the PG&E action be found to be imprudent and $6.488 million be returned to the gas adjustment clause (GAC) balancing account. TURN supports this adjustment.

PG&E argued that CMA and TURN based their challenge to PG&E's Canadian gas takes on the erroneous assumption that neither the PGT-PG&E contract nor the PGT tariff required PG&E to pay for any gas above 80% of the DCQ. PG&E urges that the PG&E-PGT contract cannot be viewed as an isolated contract, but instead must be seen as part of the chain of contracts designed to bring Canadian gas to California through the Alberta-California Pipeline Project. PG&E believes that the PGT-PG&E contract should be analyzed and coordinated with the PGT contract at the US-Canada international border, and the contracts with the Alberta producers which are all links in the arrangement to bring Canadian gas to California.

PG&E states that PGT's FERC tariff recognizes these contractual links and operational needs. Under the PGT tariff the reasonable and necessary operating expenses associated with PGT's purchase of natural gas for sale to PG&E are part of PGT's cost of service for which PG&E is responsible, reflects the integrated nature of the Alberta-California pipeline project, and ties PG&E's payment responsibility to the costs incurred by PGT to obtain gas at the international border for service to PG&E. PG&E argues that included in the reasonable and necessary operating expenses is Account 803 of the Uniform System of Accounts which contains PGT's purchased gas expense. All gas purchased by PGT is for sale to PG&E; therefore, under the tariff, PG&E is responsible for PGT's purchased gas costs

PG&E argued that CMA's concern is not that PG&E has minimized costs; instead, CMA objects that the least cost policy has cost the Electric Department more than a separate policy would. PG&E believes that concern can be better addressed through the allocation of costs from a combined strategy between the Gas and Electric Departments, by setting the G-55 rate to equitably allocate costs between the departments, while still allowing the utility to pursue the overall least cost strategy.

We believe that if PG&E had adopted the fuel strategy recommended by CMA, it would have been subject to criticism because the higher costs to its gas customers and higher overall costs. PG&E's "one-company" fuel strategy has not been shown to be unreasonable, and CMA's proposed adjustment will not be adopted. We will review the CMA proposal in the context of PG&E's general rate proceeding where we concurrently establish rates for both gas and electricity, and where we can evaluate all rate design elements underlying the G-55 rate level.

C. Fuel Oil Sale Losses

TURN argued that PG&E had failed to take into account the Commission's express directive on fuel oil inventory carrying costs in D.82-12-109 when it decided to sell fuel oil out of inventory in early 1983. PG&E's witness testified that the company decided to sell the oil at a $9.25-13 per barrel loss because this was less costly than either burning the oil and rejecting gas ($13.50 per barrel) or continuing to hold the oil in inventory ($18 per barrel for a minimum two-year holding period). TURN contends, however, that the option of continuing to hold the oil would only cost $18 if the carrying cost was calculated according to the utility's pre-tax corporate cost of capital. Prior to D.82-12-109, this would have been appropriate, as ratepayers reimbursed the utility for carrying oil in inventory at that rate. But D.82-12-109 specifically changed the ratemaking tratment of oil inventory to provide for ratepayer reimbursement of only balancing account interest on oil inventory held in excess of the safety stock. At the balancing account interest rate, the option of holding oil in inventory would have been closer to $6 per barrel for a two-year period, which is less than the $9.25-$13 cost of selling the oil at a loss. Therefore, TURN argues, PG&E was imprudent in making the oil sales and needlessly increased ratepayer costs.

PG&E argued that TURN has misrepresented our actions in D.82-12-109. PG&E agrees that the decision authorizzed PG&E to receive the ECAC interest rate on oil inventory volumes between 5.4 and 11.4 million barrels. Further, PG&E agrees that the decision provides that future oil sale losses would be judged in light of that adotped inventory treatment. However, PG&E argues that it would be unreasonable to construe this to mean that fuel oil sales should be analyzed by the company based on particular inventory "tier" and its associated carrying cost rate. PG&E points out that D.82-01-103 provided for recovery of zero carrying costs above the inventory level of 11.4 million barrels. If PG&E were to use this "zero carrying cost" as a criterion for deciding between holding such inventory or selling it at a loss it would always choose to hold it. This, according to PG&E, would ignore the fact that holding inventory does cause real costs, namely, their coporate cost of capital. Thus, using the inventory carrying cost rates allowable for ratemaking to guide their fuel use decisions would distort such decisions and lead to economic fuel sales possibilities being ignored. This would be a perverse outcome of D.82-12-109 since that decision also called on PG&E to reduce its fuel oil inventory. PG&E thus concludes that its losses on fuel oil sales were not imprudent even though they utilized the corporate cost of capital to evaluate the expense associated with the option of continued inventory holding.

We believe that PG&E decisions during the reasonableness review period to sell oil in inventory at a loss were proper economic choices. However, based on the record before us, we believe that PG&E's proposed level of cost recovery on such losses is not reasonable.

It was not the intent of D.82-12-109 to distort PG&E's fuel use decisions. Rather, it was the intent to shift some of the burden of excessive fuel oil purchases to stockholders. That decision found that PG&E had excessive fuel inventory levels that were in part caused by the company's fuel oil contract with Chevron USA, Inc. (Chevron). While not passing judgment on the PG&E-Chevron LSFO contract per se, we did conclude that "we will begin to shift some (contract-related) expenses back to shareholders with the present intention of shifting more expenses in future years." (D.82-12-109, p. 9). A mechanism for explicitly shifting some costs back to the shareholder was the two-tier inventory approach that was adopted. Whereas fuel inventory, like other utility assets, costs the utility its cost of capital to carry,[2] the two-tier inventory scheme only allowed PG&E to recovery carrying costs at a lower ECAC rate for the second, more "excessive" inventory tier. Further, for holding above the second tier, no carrying costs would be allowed in rates. For each tier, any divergence between the carrying costs allowed for rate purposes and the corporate cost of capital would be a cost borne by stockholders. This not only would allocate the burden of excessive inventory holdings more fairly, it would give the utility a strong incentive to reduce its inventory levels.

PG&E correctly points out that it would be at odds with the intent of D.82-12-109 if the company's incentive to reduce fuel oil inventory was seriously weakened because they were forced to utilize

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[2] Long-term inventory levels are financed from long-term capital sources. Occasionally, short-term increases in inventory will be financed out of short-term capital sources to meet temporary contingencies. The inventory in question here does not fall into this category, however. It had risen to higher levels only because of a misestimation of long-term needs by PG&E and an abnormally high hydro year.

the ECAC carrying cost rate or the zero carrying cost rate when analyzing whether to carry oil in inventory or sell it at a loss. The economically efficient choice between such alternatives can only be arrived at if the continued carrying option is evaluated at its higher real cost, the corporate cost of capital.

On the other hand, it would also be unreasonable and at odds with D.82-12-109 if ratepayer exposure to the costs of excessive oil purchases by PG&E were increased merely because PG&E made "cost-saving" sales of its holdings. This is precisely the problem that TURN raises. The problem can be illustrated using TURN's figures listed in its brief regarding the Apex #3 oil sale in January 1983. TURN points out that PG&E could have either sold this oil at a $12.50 per barrel loss or it could continue to carry it in inventory. Assuming a three-year inventory period, this inventory would cost roughly $27 per barrel at the corporate cost of capital to hold or approximately $9 per barrel at the ECAC rate. As noted earlier, the carrying costs allowable in rates would be $9 per barrel with shareholders carrying an $18 per barren burden ($27-9). TURN argues that because <u>ratepayer</u> costs under the holding option are $9 versus $12.50 per barrel associated with the sale, it was imprudent for PG&E to undertake the sale. PG&E argues that the sale should have been made as the economic cost of the loss on sale, $12.50 per barrel was less than the economic cost of continuing to hold the oil, $27 per barrel.

In this example, PG&E was correct in making the sale but it is unreasonable that ratepayer exposure to the costs of excessive fuel oil purchases be increased from $9 to $12.50 per barrel simply because of the sale. Rather, ratepayer exposure to the burden of this fuel oil should remain at the same level regardless of the use of the oil. Thus, in this example, $9 per barrel is allowable in rates whether the oil is held or sold at a loss. PG&E, however, is able to reduce its stockholder burden from $18 to $3.50 ($12.50 - $9) per barrel by making the proper economic choice and selling the oil.

additional evidence was adduced. One the initial day of hearing the ALJ ruled that this issue was to be deferred until completion of related civil court litigation, as immediate consideration may jeopardize an early and favorable settlement.

Although receipt of further evidence on this issue was deferred, the parties briefed this issue. TURN points out in its brief that PG&E's LSFO inventory analysis assumes a 60-day lead time to obtain additional LSFO from Chevron. Absent that arrangement, a considerably longer period of 90 to 120 days would be necessary. This would increase the LSFO safety stock inventory requirement by 700,000 to 1 million barrels. TURN states that at PG&E's assumed annual carrying cost of $9 per barrel, the added inventory would cost customers $6.3 to $9 million annually. TURN believes that $6-9 million would be a reasonable price to pay to free ratepayers of the $40 million annual facility charge and 50%-above-market oil price contained in the Chevron LSFO arrangement. TURN asks that we order that any agreement which requires PG&E to pay money to Chevron shall contain the following clause: "This agreement shall not become effective until the California Public Utilities Commission has authorized PG&E to recover in rates all payments provided therein." The general purpose of this proposal is meritorius as there are outer limits to the recovery that will be allowed. One possible option the Commission may choose to explore in the future is the proviso that in future reasonableness review periods purchases under the renegotiated Chevron contract will be compared with purchases of LSFO on the spot market, plus the extra carrying costs for the longer lead times for deliveries of spot purchases. Other options may be equally attractive and these matters should be addressed in the next reasonableness proceeding.

While we will adopt TURN's proposal, we are mindful that the record on this point in the proceeding culminating in D.82-12-109 (which was incorporated into the record by D.83-04-089)

3. <u>Capacity Sales to CVP</u>

The staff accounting witness recommended that capacity sales revenues associated with the California Valley Project (CVP) contract in the amount of $25.2 million, plus related interest of $2.7 million through January 31, 1983, be credited to the ECBA. This amount relates to a dispute between PG&E and CVP over the amount CVP owes PG&E for capacity provided. PG&E's billings to CVP reflect PG&E's interpretation of CVP's liability, while CVP has paid a smaller amount which it contends is the proper level. Pending resolution of the dispute, the staff audit report recommends that amounts billed to CVP should be credited to the ECBA on an ongoing basis. PG&E does not object to the proposed treatment, as long as the Commission will allow the company to correct the balancing account to reflect the final resolution of the issue, subject to reasonableness review, so that when the dispute is resolved, PG&E would be allowed to recover reasonable amounts credited. The staff audit recommendation should be adopted, subject to review by the Commission when the dispute between PG&E and CVP is resolved.

4. <u>ECAC Recovery on Excess Oil in Inventory</u>

The staff audit report states that for January 1983, PG&E recorded carrying costs of fuel oil in inventory in its ECAC balancing account at the commercial paper rate on the difference between the actual recorded amount which exceeded the authorized ceiling of 11.4 million barrels in inventory and 5.4 million barrels of fuel oil in inventory which was the authorized amount of fuel oil in inventory for AER recovery in D.82-12-109. The staff believes that PG&E should have recorded in its ECAC balancing account, at the commercial paper rate, fuel oil inventory carrying costs on the difference between the recorded amount of barrels in inventory ceiling (not to exceed 11.4 million barrels) authorized in D.82-12-109, and 5.4 million barrels of fuel oil in inventory commencing January 1, 1983 to properly comply with the intent of that decision. The staff recommends that fuel oil inventory carying costs be reduced by $.31 million for January 1983. The related interest effect through January 31, 1983 is $3,745. On cross-examination the staff accountant presented several alternatives to the manner in which this adjustment should be calculated.

In its opening brief PG&E advocates the staff alternate method which allows it to record carrying costs based on the difference between actual inventory volumes and the 5.4 million barrels included in AER, subject to a 6.0 million barrel annual cap. TURN states that the annual cap is a cumbersome procedure that will only lead to more difficulties, especially when less than a full year or overlapping annual periods are subject to review. TURN advocates a monthly cap, based on monthly inventory estimates underlying the adopted annual average. TURN argues that neither the staff nor PG&E has correctly applied the two-tier method advocated by it and assertedly adopted in D.82-12-109, and as the ECBA adjustment is greater than the $310,000 advocated by the staff, PG&E should adjust its ECBA calculation of oil inventory carrying costs for January 1983 and subsequent months to conform to TURN's methodology and present such calculations in its next ECAC annual review.

We believe the record is sufficient to decide this issue without carrying it forward to the next ECAC annual review. We will correct the January 1983 recorded carrying cost of fuel oil in inventory in the manner originally proposed by the staff. As we treat the carrying costs on fuel oil differently in this decision (as discussed later) no further adjustments in the ECBA are necessary.

II. ECAC ISSUES

A. Resource Mix Forecast

PG&E and our staff presented separate estimates of the resource mix for the electric sales forecasted for the period beyond the forecast period. At the request of the ALJ, our staff revised its forecast to include the additional 161 gWh (Exhibit 26). PG&E supports this treatment as it is in accord with its basic argument that its is in the best interest of it and its ratepayers to use the carryover for peaking power during the summer months when its system peaks occur.

TURN argued that the entire carryover should be included in the forecast year. The first reason advanced by TURN is that the evidence introduced in PG&E's general rate increase proceeding showed that the utility's avoided costs are higher in winter months than during summer months; therefore, it would be prudent to use the carryover in the early months of 1984. TURN also argued that PG&E's hydroelectric power forecast is seriously flawed. PG&E's forecast was developed on a "current outlook" basis using the latest snow survey for the forecast months of August through December 1983. However, for the forecast months of January through July 1984, PG&E's forecast assumed average hydro production based on historical data. The use of "normal" or "average" hydro production for the January through July portion of the forecast period produces a discontinuity as shown in the monthly projections in the following table:

PG&E Hydroelectric Power Forecast

Year	Month	gWh
1983	August	1401.1
	September	1256.0
	October	1236.1
	November	1329.1
	December	1364.8
1984	January	925.9
	February	940.7
	March	1066.8
	April	1123.7
	May	1223.7
	June	1085.3
	July	1163.7
Total for AER Forecast Period		14116.8

TABLE 3

Energy Cost Adjustment Clause
Calculation of Change in Revenue Requirement

Revision Date: August 1, 1983
Forecast Period: Twelve Months Beginning August 1, 1983

Line No.	Item	Estimated Quantity (6)	Estimated Price (7)	$(000)
	Fossil Fueled Plants			
1	Gas	181,235	$5.3541	$ 970,350
2	Oil-Residual	7,847	5.9105	46,380
3	Oil-Distillate	559	5.4472	3,045
4	Subtotal-Fossil	189,641		1,019,775
5	Geothermal Steam Plants	7,417	3.890¢	288,521
6	Nuclear Steam Plants	-	-	-
7	Purchased Electric Energy (1)	23,243	2.589¢	590,107
8	Economy Energy Credit			(30,750)
9	Subtotal			1,867,653
10	Plus: Oil Inventory Carrying Cost (8)			65,086
11	Subtotal			1,932,739
12	Less: 5% of Energy Expenses (2)			96,637
13	Subtotal: 95% of Energy Expenses			1,836,102
14	Allocation to CPUC Jurisdictional Sales (3)			1,808,010
15	Energy Cost Adjustment Account Balance, Estimated as of July 31, 1983, and Adjusted to Provide for Amortization over 12 months			(438,305)
16	Subtotal			1,369,705
17	Adjustment for Franchise Fees and Uncollectible Accounts Expense (4)			10,862
18	Total ECAC Revenue Requirement			1,380,567
19	Total ECAC Revenue at Present Rates (5)			1,275,852
20	Change in Revenue Requirement			104,715

(1) Excludes operation and maintenance payments related to certain energy purchase contracts.
(2) Line 11 x 0.05.
(3) Line 13 x .9847
(4) Line 16 x 0.00793.
(5) At rates effective June 15, 1983.
(6) In billions of Btu or gigawatt-hours.
(7) In dollars per million Btu or cents per kilowatt-hour.

principal issues in OII 82-04-02 is the appropriate allocation of fuel-related expenses for rate recovery between the AER and ECAC. Related issues considered in OII 82-04-02 which affect this proceeding are: (1) the appropriate interest rate(s) to use in calculating fuel inventory carrying costs, and (2) the cap on AER earnings variations which should be adopted.[6]

C. Operational Fuel Oil Requirement and Carrying Charges

PG&E points out in Exhibit 6 that its projected minimum fuel oil inventory requirements are made up to three basic components. The first is a year-round inventory amount of five million barrels which is needed to ensure system reliability in the face of basic contingencies such as locational gas curtailments, transmission outages, and oil delivery problems. The second is a monthly inventory requirement which is greater than or equal to five million barrels which depends on seasonal contingencies such as abnormal dry year conditions which increase the need for thermal resources, or abnormally cold winter conditions which increase high priority gas usage and decrease the amount of gas available for electric generation. This seasonal inventory requirement peaks in December, when the uncertainty about winter heating requirements and rainfall levels is greatest.

The first two components of the fuel inventory requirement represent a safety stock necessary to insure against system uncertainties. A third component of inventory arises when it is more economical to hold inventory at the December peak levels throughout the year rather than selling off the inventory after December and buying it up again in the following autumn. This component can increase the inventory requirements in the months other than December, thereby raising the yearly average.

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[6] In D.82-12-105 issued December 22, 1982, we revised the AER/ECAC allocation for Southern California Edison Company (Edison) to 10% for AER and 90% for ECAC. We placed a cap on resulting earnings variations of 160 basis points on pre-tax equity earnings.

stock would be recovered in ECAC at the current balancing account rate. PG&E argues that the entire amount should be carried at the authorized rate of return.

We will adopt 7,939,000 barrels as a reasonable operational fuel oil requirement for the forecast year. As the inventory analysis that it is based on did not explicitly include demand uncertainties or the possibility of Diablo Canyon not being on line during the forecast year, we consider it to be a relatively conservative estimate.

Following today's decision in OII 82-04-02, 5% of this inventory amount will be placed in the AER where it will be carried at the authorized rate of return and 95% of this inventory will be placed in ECAC where it will be carried at the earned rate of return. Inventory levels in excess of the adopted amount will be carried at the three-month commercial paper rate, as provided for in our decision in OII 82-04-02.

D. Estimated Expense for Facilities Charges and Underlift Payments

Facilities charges and underlift payments were discussed under a separate heading. As indicated in that discussion, no facilities charges or underlift payments have actually been made, and separate ECAC accounting treatment has been provided for the Chevron facilities charges, if any, accruing in the forecast period. Therefore, no amounts should be included for facilities charges or underlift payments.

E. Gains and Losses From Sales of Fuel Oil

No gains or losses from the sale of fuel oil are estimated for the forecast period.

F. AER Percentage

Under current procedures, PG&E fuel-related expenses are allocated on the basis of 2% to AER and 98% to ECAC. As noted above, today's decision in OII 82-04-02 allocated 5% of all forecasted fuel and fuel-related expenses to AER and 95% to ECAC for PG&E. The AER is subject to a cap of 140 basis points.

G. Change in AER Revenue Requirement For Forecast Year

The following table sets forth the change in the AER revenue requirement for the forecast year based on the foregoing discussion.

TABLE 6

Pacific Gas and Electric Company
Annual Energy Rate
Calculation of Change in Revenue Requirement

Line No.	Item	M$
1	Carying Cost of Oil Inventory	$ 65,086
2	Est. Fuel & Purchased Power Expenses	1,867,653
3	Subtotal	1,932,739
4	Five Percent of Energy Expenses*	96,637
5	Allocation to CPUC Jurisdictional Sales**	95,158
6	Adj. for Franchise Fees & Uncollectible Accounts Expense***	755
7	Total AER Revenue Requirement	95,913
8	Less: AER Revenue Authorized in Decision 82-12-109	88,074
9	Change in Revenue Requirement	7,839

*Line 3 x 0.5

**Line 4 x .9847

***Line 5 x .00793

IV. ERAM

A. ERAM Revenue Requirement

PG&E's ERAM request is based on D.82-12-113, D.82-12-055, and D.82-12-056 concerning the calculation of ERAM revenues. Staff auditors have reviewed PG&E's calculations and are in agreement with the ERAM revenue requirement. No other party objects. We will adopt

> cause for the late request is shown and unless the requirements of Rule 76.23 are met and unless the participant can demonstrate that, absent participation by the participant, an important issue has not or will not be adequately considered in the proceeding."

PG&E claims that TURN has not shown good cause for its late request, as required by Rule 76.31(a), and that TURN's request was not filed within five days after its appearance, as required by Rule 76.31(b). Further PG&E asks the Commission to determine the applicability of Rule 76.31 to PG&E's request.

Our rules clearly contemplate the filing of Notices of Intent at three separate intervals during the pendency of Commission proceedings. Two of these intervals are covered by Rule 76.23 which specifies that such Notices are to be filed either before commencement, or after completion, of evidentiary hearings. In the third situation, under Rule 76.31, a participant may make a request for a finding of eligibility for compensation after evidentiary hearings have begun. In such a situation, the logistical problems of considering such a motion while hearings are ongoing, militate in favor of the requirement of a good cause showing. Such logistical problems are not present when a Notice is filed before commencement, or after completion, of evidentiary hearings, and in those situations, the good cause showing is not required.

TURN's Notice was filed, not during the pendency of evidentiary hearings, but after those hearings were completed. Thus Rule 76.31 is inapplicable to TURN's filing.

While TURN has complied with Rule 76.23, we reserve a determination whether TURN has made a substantial contribution to the proceeding pending review of further appropriate filings made under Rules 76.26, et seq.

8. An operational fuel oil requirement of 7.9 million barrels is reasonable for the forecast period and is adopted for the purpose of this proceeding.

9. Carrying costs on the adopted operational fuel oil requirement should be recovered in accordance with the findings on this issue set forth in the decision issued today on OII 82-04-02.

10. No facility or underlift charges, and no gains or losses from sales of fuel oil, are estimated for the forecast period.

11. Fuel related expenses, including carrying costs on the adopted operational fuel oil requirement, shall be recovered in ECAC and AER in accordance with 95%/5% split and related cap on earnings adopted in the decision issued in OII 82-04-02.

12. The adopted fuel related expenses, including carrying costs on the operational fuel oil requirement, and the related ECAC and AER revenue requirements for the forecast year set forth in Tables 3, 4, and 6 are reasonable for the purposes of this proceeding.

13. A 12-month period to amortize the ECBA is reasonable.

D. <u>ERAM Issues</u>

1. The calculation of the ERAM revenue requirement for the forecast year in Table 7 is reasonable and is adopted for the purposes of this proceeding.

2. Part E, No. 6(a)(2) of PG&E's Preliminary Statement should be revised to show that revenue for services rendered during the month at base rates, rather than amounts billed, should be recorded against the ERAM account.

E. <u>Other Issues</u>

1. The rate design proposed by PG&E is in accordance with the requirements of D.82-12-113 and is reasonable for the purposes of this proceeding.

2. The revenue changes authorized by this order should be recovered over a 12-month period.

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 schedule shall become effective not earlier than August 17, 1983, and shall comply with General Order 96-A. The revised schedules shall apply only to service rendered on or after their effective date.

2. PG&E shall amend its Preliminary Statement on or before August 17, 1983 as indicated in the opinion.

This order is effective today.

Dated AUG 17 1983, at San Francisco, California.

I concur in part and dissent in part.

~~I will file a written dissent.~~

/s/ PRISCILLA C. GREW
Commissioner

VICTOR CALVO
DONALD VIAL
WILLIAM T. BAGLEY
Commissioners

Priscilla C. Grew

Commissioner Leonard M. Grimes, Jr., being necessarily absent, did not participate.

APPENDIX B

Residential Bill Comparison

Monthly Usage	Present Bills	New Bills
240 kWh	$12.30	$12.44
500	29.62	29.95
1,000	72.10	72.90

(END OF APPENDIX B)