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Decision 89-05-073 May 26, 1989

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Pacific Gas and Electric Company for authority to revise its rates and tariffs effective January 1, 1989 in its annual cost allocation proceeding.	Application 88-09-032 (Filed September 15, 1988)

(Appearances are listed in Appendix A.)

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OPINION

In this order, we address Pacific Gas and Electric Company's (PG&E) annual cost allocation proceeding (ACAP) application. PG&E filed this application on September 15, 1988, requesting authority to increase its gas rates by $221.6 million. On December 12, 1988, PG&E modified its request to $298.0 million, mainly to reflect changes in oil prices. On February 9, 1989, PG&E modified its request to $290.3 million to update the balancing accounts for recorded January 31, 1989 balances. Of this amount, $111.2 million represents a net increase in balancing account undercollections that PG&E expected as of January 31, 1989. The remaining $179.1 million is due primarily to forecasted changes in gas costs and throughput. The application also requests certain modifications to the existing Commission program established by previous orders.

I. Summary

This decision grants PG&E a revenue increase in the amount of $151.4 million for the test period, January 1, 1989 through December 31, 1989. Balancing account undercollections and forecasted changes in throughput and gas costs represent most of the increase. This change in revenue requirement translates to a 5.8% increase in residential rates, and a 4.9% increase in commercial rates. While some noncore transportation rates increase as much as 13.0% (GIND), average noncore transportation rates decrease by .2%. Procurement rates for the noncore portfolio are not established in this decision as these are posted and may change bimonthly in response to market conditions.

This decision also addresses methods for forecasting throughput and noncore customer discounts required to keep large industrial users on PG&E's system. Much of the proceeding focused on PG&E's methods and models. In general, we find that PG&E's models do not adequately describe customer behavior in a number of

ways. For example, we modify PG&E's models so that they account for the effects of demand charges on customer decisions with respect to fuel switching. We also modify the models to take into account the effects of core election on model outputs.

We find that PG&E's discount adjustment model is too complex and inaccessible to the parties, and adopt a simpler and more understandable alternative. To facilitate efforts to improve ACAP modeling, we plan to hold workshops prior to hearings and following the filing of PG&E's next ACAP application.

In addition, today's order addresses PG&E's proposed gas and oil price assumptions. We find that an appropriate oil price forecast for the test year is $17 per barrel, and that changes in oil prices do affect gas prices. The adopted core weighted average cost of gas (WACOG) is $1.944 per million British thermal unit (MMBtu). The adopted noncore WACOG is $2.20 per MMBtu.

Today's order incorporates the allocation effects of PG&E's 1989 attrition year increase of $37.18 million for PG&E's gas operations adopted in Resolution G-2838. In general, the order retains the cost allocation and rate design principles established in Decision (D.) 87-12-039.

II. <u>Procedural Background</u>

A. <u>The Purpose of the ACAP</u>

Today's decision implements PG&E's first ACAP. We established this proceeding in D.87-12-039, which addressed cost allocation and rate design principles based on broad policies set forth in earlier orders.

The Commission developed the ACAP as part of its gas regulation program which seeks to respond to changing market conditions for the gas utilities. In recent years, changes in federal policy and gas markets have required that we reconsider our regulation of the gas utilities in order to make them competitive and to promote efficient market transactions.

As part of this program, the ACAP allows the utilities to begin the process of moving rates toward cost by allocating costs to cost-causers. The regulatory structure underlying the ACAP places increased risk on the gas utilities and provides them new opportunities in noncore markets.

More specifically, the purpose of the ACAP is to:

- o Allocate fixed and variable costs between customer classes
- o Forecast gas costs and throughput for the test period
- o Amortize balancing account undercollections and overcollections
- o Revise rates to reflect changes in throughput and expenses

B. Summary of the Proceeding

PG&E filed its ACAP application on September 15, 1988. It initially requested that the Commission increase its revenue requirement by $221.6 million. On December 12, PG&E modified its request mainly to reflect changes in oil prices. PG&E's December 12 filing increases its original request to $298.0 million. On February 9, 1989, it further modified its request to include recorded January 31, 1989 account balances. PG&E's revised request is $290.3 million. Of this amount, $111.2 million represents expected increases in balancing account undercollections.

PG&E's request is based on a throughput forecast and an estimate of gas costs for the test period, January 1, 1989 to December 31, 1989. Its proposed cost allocation between customer classes is, according to PG&E, consistent with Commission directives in D.87-12-039 and with Senate Bill (SB) 987, which required continuation of the existing cost allocation through January 1, 1991. PG&E's proposed rate design, as modified, would increase residential rates by 12.5% on average, and increase noncore transport rates by an average 22.6%.

The following parties filed testimony in this proceeding: the Division of Ratepayer Advocates (DRA), Toward Utility Rate

Normalization (TURN), California Industrial Group (CIG), Mission Resources (Mission), California Cogeneration Council (CCC), the California Department of General Services (DGS), Southwest Gas Company (Southwest), and Salmon Resources Ltd. with Mock Resources, Inc. (Salmon/Mock). The testimony of Salmon/Mock regarding unbundled brokerage fees was deferred following issuance of D.88-12-045. Southern California Edison Company (SCE) and Canadian Producer Group (CPG) filed briefs.

Fourteen days of hearings were held in Phase I of this proceeding. The case was submitted on January 27, 1989.

C. Scope of the Proceeding

A number of parties moved to strike all or portions of the testimony of CIG, Mission, DRA, Southwest, and TURN. All of the motions were granted on the grounds that subject testimony was beyond the scope of this first ACAP proceeding. In some cases, testimony appeared to conflict with SB 987 which directed the Commission to retain existing cost allocation methods until January 1, 1991. We concur with the administrative law judge's (ALJ) ruling that experience with our new program is limited, and that we should consider cost allocation changes only in future ACAP proceedings. We are also committed to complying with SB 987, but recognize that cost allocation which assigns costs to cost causers is an integral component of our new gas regulation program and critical to its ultimate success.

D. Document Production

During the first week of hearings, Salmon/Mock, TURN, and others requested that the ALJ require PG&E to release certain customer-specific data which was used as inputs to PG&E's discount adjustment model. The motion was granted subject to protective order. PG&E appealed the ALJ's ruling on the grounds that the information was too sensitive to release publicly.

Subsequently, PG&E filed, on December 12, modifications to its discount adjustment model which did not use customer-specific inputs. The ALJ withdrew the ruling in recognition that PG&E's case in chief no longer relied upon the customer-specific information.

During hearings, PG&E objected to requests by Salmon/Mock to produce PG&E's contract with Enron, a supplier of gas from the Southwest. The ALJ ordered PG&E to produce the contract because, under our policy, the utilities must document their costs with all appropriate information unless imminent and significant harm would result. Prior to its release of the document, PG&E agreed to have its witness cross-examined on the contract's elements. Following cross-examination, Salmon/Mock withdrew its request for a copy of the contract. We are satisfied with the outcome of this conflict, but remind PG&E that it must provide any information to parties requesting it when the utility uses such information to estimate costs. It is not enough for the utility to assert future costs: they must be documented.

E. Brokerage Fees

On December 9, 1988, the Commission, in D.88-12-045, addressed PG&E's petition for modification of R.88-08-018, noting that the policy issues regarding brokerage fees would be resolved in its procurement rulemaking. Implementation of brokerage fees would be included in this ACAP in a second phase of the proceeding. Accordingly, we will address brokerage fee implementation following additional hearings in this proceeding.

F. Attrition Year Cost Allocations

On December 19, 1988, the Commission issued Resolution G-2838, addressing PG&E's 1989 attrition increase request. That resolution directed PG&E to propose in this ACAP proceeding a simpler method for allocating future attrition year revenue changes. Since many of the parties' original filings did not specifically address this issue, it will be considered in Phase II of this proceeding.

III. Major Issues

Forecasting the gas revenue requirement involves investigation and resolution of many interactive factors. Five major categories of issues were considered in this ACAP.

1. Gas Throughput
2. Cost of Gas
3. Cost Allocation
4. Revenue Requirement
5. Rate Design

A. Gas Throughput

Gas throughput is the total demand for natural gas from the PG&E system, including gas purchased and sold to PG&E's customers and transportation of customer-owned gas on PG&E's system.

In this proceeding both PG&E and DRA presented forecasts of total throughput on the PG&E system for the forecast period. The forecasts for the residential, commercial, and industrial classes were derived through the use of econometric (ET) models. These models determine the effects of such factors as weather, economic activity, and alternate fuel prices on gas usage. Forecasts for other customer classes, including enhanced oil recovery (EOR), utility electric generation (UEG), and cogeneration, were determined exogenously (that is, outside the econometric models).

PG&E also employed one other computer model: the discount adjustment (DA) model. The output of this model was used to adjust the forecast of industrial throughput downward to reflect the fact that some industrial customers will remain on the system only if they receive a discount below the embedded cost of service default rates. Absent a discount they would switch to a cheaper alternate fuel. This "discount adjustment" was first authorized in the implementation decision, D.87-12-039. It became the focus of controversy in this proceeding. The issue was not whether the adjustment should be performed but how it should be performed. PG&E advocated the use of its computer model while TURN, CIG, and other parties urged the use of simpler mechanisms. Before describing the different proposals, we first review the conceptual rationale underlying this adjustment.

The discount adjustment grew out of a dispute between DRA and PG&E in the implementation proceeding. In that proceeding DRA presented an industrial throughput forecast which assumed that all existing customers would be retained on the system once the new regulatory structure was implemented. DRA reasoned that PG&E would be able to retain existing customers under the new program since it had the flexibility to discount to those customers whose value of service was below the embedded cost of service default rates. PG&E, on the other hand, presented a forecast which assumed no discounting and significant load loss. The utility's concern was that the use of a forecast which assumed discounting would result in a built-in revenue shortfall. This would occur because the forecast is used to allocate embedded costs. Put simply, the use of a forecast based on discounting would result in more costs being allocated to the industrial class than could be recovered in rates.

TURN proposed a compromise which would avoid this problem. In its simplest form the TURN proposal involved adjusting the forecasted volume of throughput in proportion to the estimated need for discounting. The goal of the exercise is to match the revenues which can be obtained from industrial customers with the costs that are allocated to them. We ultimately adopted this adjustment.

The operation of discount adjustment is perhaps best understood through a simple example initially presented by TURN. Assume that the embedded cost of service for industrial customers is 10 cents and that the total throughput which could be retained through discounting is 100 therms. Also assume that the competitive rate for retaining these customers is only 8 cents. That is, the 100 therms of a throughput can only be achieved through a 20% discount which produces $8 in revenue (8 cents x 100 therms). Under the discount adjustment the throughput forecast of 100 therms is reduced by 20% to 80 therms. This results in $8 in cost being allocated to the class (10 cents embedded cost x 80 therms) which is the amount of revenue which can actually be recovered. Through this adjustment the revenue forecast becomes obtainable and the utility is given a fair opportunity to earn its return.

The following sections describe and discuss the different proposals in this proceeding for implementing the discount adjustment. We ultimately adopt the proposal put forth by TURN.

1. Evaluation of the PG&E Models

PG&E's estimates of throughput include use of two types of models. The ET model forecasts throughput econometrically by estimating the effects of such variables as fuel prices, weather, and economic growth on demand.

The DA model estimates revenues by forecasting the discounts required to keep large customers (P2B, G-IND, and COGEN) on PG&E's system. The DA model is used to develop an average industrial transport rate to input into the ET model, to derive a discount adjustment percent for P2B, G-IND and COGEN, and to calculate forecasted billing determinants to which industrial demand charges will be applied.

The PG&E model utilizes 1987 recorded data, estimated alternative fuel prices, and estimated, or "seed", rates. These inputs are used to determine both the amount of load requiring a discount and the level of discounting needed to keep that load.

This is accomplished by calculating two bills for each of PG&E's 1,100 industrial customers. The first bill, the alternative fuel bill, is the maximum amount that a customer would be willing to pay for gas service. It is calculated as the sum of the customer's alternative fuel cost plus a premium for natural gas. The second bill, the "standard service bill", is the customer's estimated bill on the applicable standard service gas tariff using "seed" or estimated standard service rates.

The model assumes that a customer whose alternative fuel bill exceeds its standard service bill for the test period can be served at tariff rates and will not require a discount. Customers whose standard service bill exceeds their alternative fuel bill will require a discount. The amount of the required discount is the difference between the two bills. The required percentage discount relative to each noncore group is then the relationship of the total required discounts for customers in that group to which the group revenues would be at standard service rates. This percentage is then subtracted from the forecasted noncore volumes to obtain the discount adjusted forecasts which are ultimately used for cost allocation and rate design. As noted earlier, the issue addressed by this adjustment is the amount of revenues which can be obtained from a given volume of throughput.

The DA model is the more controversial of the two models because of its complexity and due to the effects of its outputs on throughput estimates. The interaction of the two models was also the subject of debate.

a. <u>PG&E</u>

PG&E comments that the purpose of the DA model, conceptually adopted by the Commission in D.87-12-039, is to recognize the value of gas, relative to other fuels, to noncore customers. According to PG&E, estimating customers' willingness to pay in advance frees the Commission from reviewing every negotiated agreement. PG&E recovers revenue requirement based on its negotiating skills and knowledge of the market. PG&E believes the model is simple enough for the parties to understand and has agreed to make the model accessible to the parties.

PG&E's original DA model used customer-specific data to estimate required discounts. PG&E amended its original filing so that customer-specific data was not used as model inputs. The revised showing uses average customer data.

b. CIG

(1) The Models

CIG challenges PG&E's methodology on the grounds that the models systematically underestimate throughput. CIG states that PG&E has an incentive to underforecast noncore industrial throughput in order to lower PG&E's risk of recovery.

CIG cites a number of ways the models together underestimate throughput. The econometric models, according to CIG, are specified in conjunction with the DA model so that an unadjusted throughput forecast of lost load, once made, cannot be regained even when assumptions are changed. The ET model will predict a loss of load that is actually being retained by way of negotiated transmission rates.

Moreover, a reduction in average gas prices or an increase in the premium does not result in a corresponding increase in throughput. When lower gas prices were assumed, the DA model increases the revenues collected from the G-IND class, increasing the discount ratio as well as the average transport rate. The higher discount ratio translates into a higher adjusted throughput for ratemaking purposes, but the higher average industrial transport rate offsets the lower gas costs in the seed rate calculation. Thus, the unadjusted throughput level, which reflects the real level of gas demand, is maintained despite significant reductions in gas costs.

CIG argues that PG&E's DA model does not take into account any potential discounts from gas suppliers in response to competitive pressures. Additionally, since the ET model does not use historic data, it cannot provide reliable estimates of throughput.

Finally, CIG notes that PG&E's use of econometric model outputs as inputs to the DA model, while using DA model outputs as inputs to the econometric model is a circular and self-fulfilling prophecy.

(2) CIG's Proposal

CIG believes the PG&E methodology is so flawed that it should not be used to estimate throughput. CIG recommends instead that the Commission adopt an estimate based on PG&E's most recent recorded annual period.

Under CIG's proposal, the Commission would consider as "unadjusted throughput" PG&E's recorded industrial throughput for the period June 1987 through June 1988. That amount is 1,680 million therms (MMth). According to CIG, this throughput is reasonable because most recent recorded data do not show any evidence of a decline in throughput. Using this throughput does not make the illogical assumption made by PG&E that gas prices will not respond to lower oil prices.

To develop an average discount, the Commission should use the average discounts negotiated by PG&E in current contracts, which is now 61% of the existing default rate. CIG points out that the resulting $.0975 per therm discount rate is comparable to PG&E's existing average G-IND rate of $.098 per therm.

To implement CIG's recommendation, the volumes subject to discounting are estimated. CIG's witness assumed that 700 MMth would be discounted based on the 679 MMth currently under discounted contracts. The 61% discount is then applied to those volumes to yield a "full rate" equivalent volume of 427 MMth. This full rate equivalent volume is then added to the volumes not subject to discounting (that is, the unadjusted throughput less discounted throughput) to yield the discount-adjusted volume to be used for ratemaking purpose. Using the 1.68 MMth as unadjusted throughput, the CIG methodology yields a discount-adjusted throughput of 1,407 MMth.

c. TURN

(1) The Models

TURN observes numerous shortcomings in the DA model. First, TURN states the model improperly applies 1989 market conditions to historical usage patterns even though significant changes in the market have occurred since 1987. For instance, the company's procedure assumes that all cogenerators on line in 1989 will have the same load patterns and alternative fuel costs as those of a much smaller group who were operating in 1987.

TURN believes 1987 data is not representative of 1989 market conditions because that period precedes gas industry restructuring and the introduction of demand charges. For this reason, TURN recommends that the Commission rely on aggregate rather than customer-specific load data for forecasting.

TURN also suggests that in determining the average level of necessary rate discounts, PG&E should use the discount percentage developed for existing contracts and multiply them by the volumes in those agreements. TURN makes this suggestion on the basis that those contracts are the best evidence of the level of discounts actually required by the marketplace and they are already public information.

TURN also challenges the application of the outputs of the DA model to the ET model. According to TURN, PG&E has double-counted load loss of 33 MMth. The ET model predicted 33 MMth of load loss, load which was discounted by the DA model. In effect, according to TURN, rate discounts were found necessary for load already assumed lost in the ET model. Since the ET model does not predict individual customer fuel switching behavior, this problem cannot be corrected.

TURN adds that the fact that Negotiated Revenue Stability Account (NRSA) balances are almost zero for 1988--even though oil prices were well below the assumed level--is evidence that PG&E'S forecasting methods, which were used for the last forecast, are systematically biased. Similarly, the drop in oil prices at the end of 1988 did not lead to significant increases in contract negotiation. PG&E reports that only 80 of its 1,100 industrial customers have so far negotiated contracts. On this basis, TURN believes it is unreasonable to assume that 96% of industrial volumes will be subject to discounted rates during the test period, as PG&E's models predict.

TURN is also critical of the econometric model itself. First, TURN states that for econometric models to work, there must be sufficient historical data. PG&E uses a single average gas price.

Like CIG, TURN observes that the econometric model will assume lost loads that will not actually be lost because it employs an average negotiated rate level instead of a minimum negotiated rate level. This problem, according to TURN, is not remedied by the fact that the historical gas prices used as inputs to the ET model also represent average industrial prices because PG&E has had greater negotiating flexibility since May 1 than it has had in the past. Accordingly, PG&E will sell gas at a wider range of discounted rates than is reflected in the historical data base.

To remedy this problem, TURN recommends that the ET model be run twice, once using the default transmission rate and again using the minimum floor rate. The default transmission rates are the rates noncore customers would pay for transportation absent negotiation. The results of the initial run would establish the forecast of throughput at default rates. The difference between this run and that using the minimum floor rate would represent the additional volumes that could potentially be regained through discounting. TURN's witness stated a simpler approach would be to add an estimated average exit charge to the oil price forecast used in the ET model to reflect the fact that fuel switchers would be paying these costs in addition to the price of the oil itself.

Finally, TURN states a preference for DRA's econometric model over PG&E's because, although the models are similar, DRA's yields a lower forecast error than PG&E's when applied to recent historical data.

(2) TURN's Proposal

TURN recommends that the Commission reject PG&E's DA model, and goes so far as to disassociate itself from the model which has been referred to conceptually as the "TURN adjustment".

TURN proposes a simpler analysis which follows essentially the same logic as PG&E's DA model. The analysis relies on the use of aggregate data for large groups of customers with the same alternative fuels rather than individual customer data which TURN states is of dubious reliability. Under the TURN proposal, the cost of alternate fuels and gas is directly compared on a cost per unit basis. If a particular alternative fuel is cheaper than gas service at default rates, a percentage discount is calculated and applied to the volume of gas forecasted to be transported to customers with that particular alternate fuel. TURN notes that the methodology is a relative simple manual calculation which can be applied to all utilities without complex computer applications.

TURN describes the method in the following manner using as an example industrial customers with Number 6 fuel oil as their alternative fuel. The analysis starts with the forecasted unit cost of Number 6 fuel oil plus the adopted premium for gas usage. A factor representing the unavoidable demand charges that a customer must pay if he switched fuels is then added to alternate fuel price. TURN recommends that one half of D-1 charge plus all of the D-2 charge be used to represent the cost that would appear avoidable to a customer on an annual basis. The alternate fuel price plus the premium plus the unavoidable demand charge represents the total cost of burning Number 6 fuel oil. The average commodity cost of gas is then subtracted from this total. This average would be based upon a weighting of the core and noncore WACOGs. The result is the maximum potential transport rate for this customer class expressed in cents per therm. If the rate is higher than the expected default rate, no discount is required. If the maximum rate is less than the default transportation rate for gas service, the required percentage discount must be calculated. This percentage would be multiplied by the forecast of unadjusted throughput for customers with that alternative fuel to determine the appropriate discount adjustment volume. This volume amount is then subtracted from the forecast of unadjusted throughput for cost allocation and rate design purposes.

This approach can also be used to derive average transport rates to plug into the ET model by selecting either the "maximum transport rate" or the default rate for each fuel type, weighted by volume, whichever is lower. Percentage splits for each fuel type would have to be determined, and have been developed in the record. In each case, according to TURN, GC-2 or SCE volumes would also have to be factored into the transport seed rate.

TURN states its methodology does not provide results which vary significantly from those provided by PG&E's methodology. The advantage of the TURN model is its simplicity and understandability. It may be used to estimate all noncore class rates and transport rates.

TURN also suggests the Commission hold workshops shortly after this proceeding which would allow the parties to explore the models in more depth.

d. DRA

DRA notes that the PG&E models have created a great deal of confusion in this case and recommends a simpler approach to PG&E's DA model. DRA states that the model cannot be run by the parties and the data base of 1,100 customers is unwieldy. DRA also expresses concern that the customer-specific information in the originally filed model demands a secret review of the results, contrary to the public hearing process.

DRA supports TURN's proposal on the grounds that it is simple, accessible to parties, and can be applied to all utilities. It also incorporates the effects of demand charges and core election. According to DRA it provides reasonable inputs to the econometric model.

DRA is not as confident about CIG's approach in large part because the model does not account for changes in the relationship between gas and oil. DRA is also reluctant to abandon the ET model, as proposed by CIG.

e. CPG

CPG believes there are design flaws in both PG&E's and DRA's models which yield unacceptable results. CPG points out that the models provide counterintuitive results in that when the gas premium is increased in the DA model, the ET model forecasts lower throughput. Both models appear to treat the premium as an additive to the cost of gas rather than to its value to customers.

CPG also states that there exists between the models a circularity problem that occurs because the models cannot be iterated enough times to reconcile the discrepancies between projected revenues and revenue requirements. CPG suggests that the models are not very useful at this time because of their complexity and because of inexperience with them.

CPG proposes that the Commission adopt policy guidelines in this proceeding which will foster development of models which are simpler and more internally consistent. In the interim, CPG recommends adoption of TURN's approach which uses a single set of alternative fuel prices and which does not require complex computer applications.

f. DGS

DGS states that PG&E's econometric industrial forecast is assumed to include all GC-2 sales. The low GC-2 rates, however, are not included in the development of the seed rate by the DA model, resulting in a forecast that is too low. DGS proposes that the Commission correct this error by ordering the econometric model to be run with a final seed rate based on a weighted average of 83% of the seed rate that would otherwise have been developed and 17% of the average GC-2 rate to reflect the percentage GC-2 volumes.

g. Salmon/Mock

Salmon/Mock supports the proposals of CIG and TURN. Salmon/Mock argues that, contrary to D.87-12-039, the PG&E discount model fails to assume that upstream pipelines and producers could be assumed to bear a portion of the burden of discounting.

h. PG&E Rebuttal

PG&E states its methodology is relatively objective. It argues that using existing contracts requires the Commission to make judgments about the reasonableness of the contracts, or else reward utilities that are poor negotiators by allocating less revenues to their noncore class and placing the utilities at less risk. PG&E states that using forecasted rather than historical data in estimating throughput and revenues takes into account expected market changes.

PG&E also states that use of 1987 recorded data is a reasonable way to approximate use in 1988 and 1989 after scaling the data. Use of 1987 recorded billing data, according to PG&E, yields more accurate results than using no individual billing data, contrary to TURN's assertions.

i. Discussion

PG&E has attempted to determine 1989 throughput by looking at economic factors, and following an assessment of noncore volumes which could be retained through discounting transportation rates. PG&E's models are, for the most part, thoughtful and sophisticated. Because this is the first ACAP, PG&E's task was formidable. The concept of a discount adjustment model is new.

The risks associated with inaccurate forecasting are considerable under our new regulatory program.

While we commend PG&E's efforts to provide an acceptable framework for determining discounts and throughput, we have serious reservations regarding certain model specifications which have been the subject of much controversy in this proceeding.

Some observations of market behavior demonstrate intuitively the shortcomings of PG&E's model results. As TURN points out, PG&E's industrial throughput has increased from 1,254 MMth in 1986 to 1,528 MMth in 1987 to 1,591 MMth in 1988. PG&E's models predict a severe reversal of this pattern, estimating a drop of over one-third to 1,231 MMth in 1989. As CIG reports, 61% of volumes required discounts in 1988; PG&E's models predict that 96% will require discounts in 1989.

Some of the biases in the models are a result of implausible input assumptions which we will address separately.

Aside from the issue of model inputs, model designs are troublesome. To begin with, the parties observe correctly that PG&E's models and the way they interact are very complex. A great deal of time was spent in the hearings in efforts to understand the most basic inner workings of the discount adjustment model and the way it was used in conjunction with econometric models. The complexity of the models made it difficult to analyze inputs and results. Adding to this source of difficulty is the fact that the parties could not have access to certain customer load information, which is the backbone of the DA model.

The models have other serious technical problems which intervenors identify. Among them is the way the models together appear to double-count some load loss, and the failure of ET model throughput estimates to fall when gas prices assumptions are reduced in the DA model.

Model specifications do not allow an assumption that gas suppliers will be forced by market conditions to discount their product, thus implying that purchasers are without any negotiating power.

In spite of their apparent sophistication, the ET model and the DA model do not provide results which are consistently logical. Attempting to perfect those models and the way they interact is a task we cannot hope to accomplish in this proceeding. Some adjustments may be made to improve them and we will require those adjustments where appropriate. PG&E's discount adjustment model, however, is not salvageable. It is just too complex and too difficult to use, primarily because of its reliance on customer-specific bill calculations and load information.

We appreciate the efforts of CIG and TURN to develop alternative methods of calculating discounts and throughput. CIG's approach has intuitive appeal because it is simple and uses existing information regarding necessary customer discounts. It requires no econometric modeling or assumptions regarding future gas prices. While CIG's approach is commendable, we are concerned that it is too simple and fails to account for changing relationships between oil and gas prices and other changing market conditions, as DRA points out.

We believe TURN's method is more appropriate. Like the CIG model, it is simple and does not require the use of confidential information. It takes into account historical information and provides results which are intuitively sound. It appropriately accounts for the premium and demand charges. In addition, TURN's model takes advantage of appropriate econometric methods and recognizes forecasted values for gas and alternate fuels. TURN's method is a reasonable alternative to PG&E's DA model, and we will use it in our calculation of required discounts to transport rates for large noncore customers. The TURN formula is presented graphically in Appendix B, Table 1.

Finally, we will make DGS' proposed adjustment to the ET model, which incorporates the lower GC-2 rates in the seed rates.

Estimated discounts and discount volumes for industrial customers are presented in Appendix B, Table 1. Adopted throughput is shown in Appendix B, Table 2.

While we endorse TURN's model in this proceeding, we recognize that refinements or changes to it may be appropriate as PG&E and intervenors gain experience with ACAP forecasting and the marketplace. Accordingly, we invite PG&E and other interested parties to propose changes in future ACAPs.

We will entertain model changes under certain conditions. First, we will not estimate throughput, revenues, revenue requirements, or required discounts using data which cannot be reviewed by the parties to the ACAP proceeding. Second, we will be reluctant to revise the conceptual changes we have made, for instance, those regarding the effects of demand charges and core election, discussed below, without a strong showing. Any proposed models or changes to the models should be understandable, simple, and intuitively sound.

At TURN's suggestion, we will direct Commission Advisory and Compliance Division (CACD) to hold workshops on the models adopted in this proceeding after PG&E files its application and prior to hearings in the next ACAP. The purpose of those workshops will be to help interested parties to understand the models, specifications, and shortcomings.

2. Model Assumptions

a. Economic Activity

Activity in the economy is one input in the econometric model. PG&E forecasted a 30% probability of recession in 1989 and weighted its inputs accordingly. DRA argued that PG&E's forecast was too pessimistic, citing Data Resources Inc. (DRI) and the University of California at Los Angeles forecasts of economic activity in the state.

DGS concurs with DRA that we should not assume a recession will occur in 1989. DGS suggests that if the Commission adopts DRA's estimate of economic activity in 1989, it should also adjust the industrial throughput forecast accordingly. DGS suggests using PG&E's higher estimate of a 2.4% increase in industrial production rather than DRA's estimate of 1.4%, to be consistent with a nonrecession forecast.

TURN also supports DRA's estimates of economic activity.

We concur with DRA that most economic observers do not foresee a recession in 1989. We will also adopt DRA's estimate of growth in industrial production as a reasonable corollary to its estimates of economic activity.

b. Alternate Fuel Prices

Fuel prices affect model outcomes and are used in both the discount adjustment model and the econometric model. Higher prices for alternate fuels--propane, Number 2 fuel oil and Number 6 fuel oil--lead to higher throughput, other things equal, because gas prices are relatively more attractive to customers.

(1) Propane

PG&E estimates an average wholesale price for propane of $.282 per therm. PG&E uses a wholesale, rather than delivered, price because propane is costly to transport. Most customers who use propane do not require transport and purchase it at the wholesale rate.

DRA argues that some of PG&E's customers buy propane at delivered prices, and propane price estimates should be weighted accordingly. At DRA's request, PG&E estimated the number of customers who purchase propane at delivered prices to be about 23%. PG&E also presented average delivered rates which are estimated by the Lundberg Company to be $.421 per therm adjusted to 1989 dollars. PG&E characterizes the Lundberg survey as unrealistic, but did not provide alternative estimates of retail propane prices.

We concur with DRA that the estimated propane price for 1989 should be a weighted average of wholesale and retail rates to reflect customers who purchase propane at retail rates. We will use the Lundberg survey in the absence of other reasonable estimates. After adjusting for adopted crude prices, our adopted propane price is $.361 per therm.

(2) Number 6 Fuel Oil

PG&E estimated significant reductions in oil prices in 1989, down to $14.62 per barrel, or $.196 per therm. PG&E's original application estimated oil prices in 1989 to be $19.12. PG&E reduced this estimate following oil price reductions in late 1988.

DRA estimated crude oil prices would average $17 per barrel during 1989, equal to $.285 per therm for the refiner's acquisition cost, and $.254 per therm for the delivered price. DRA based its estimate on the average refiners' acquisition cost, using EIA's Third Quarter 1988 Short Term Energy Outlook. DRA's estimate attempts to anticipate the effects of OPEC price-setting meetings held during 1988. DRA notes that EIA used a higher OPEC production level than PG&E and still came up with a higher forecasted oil price.

TURN supports DRA's estimate of crude oil prices. TURN points out that the OPEC meeting that established the new quotas took place after both the DRI forecast of $18.30 per barrel and the EIA reduction to $15 per barrel. TURN submits that DRA's estimate is conservative.

TURN also states that the Commission must translate its adopted Number 6 fuel oil price into prices for other products. TURN suggests using DRA's formula to develop appropriate terminal and delivered prices for Number 6 fuel oil.

Generally, Salmon/Mock urges against a forecast of dramatic reductions in fuel prices because such a forecast could have a significant effect on industrial default rates.

PG&E asserts that DRA's estimate is based upon outdated data since the most recent EIA forecasts reduced the 1989 oil price from $17 per barrel to $15 per barrel. PG&E also argues that, contrary to DRA's assumption, OPEC price setting agreements have not been honored in the past.

PG&E's forecast appears to be based as much on current prices as on anticipated prices for the test period. Oil prices have historically fluctuated significantly over short time periods.

We have no reason to believe today's oil prices will continue through 1990. DRA's price forecast is well within the range of industry forecasts for the coming year and is a conservative estimate of oil prices. We will adopt DRA's $17 per barrel forecast which translates to a burnertip price of 25.4 cents and a delivered price of 28.5 cents.

(3) Number 2 Fuel Oil

Number 2 fuel oil is used as an input to the DA model. PG&E estimated $.323/therm for this commodity. DRA accepted this estimate, but noted that this price should be reduced if the Number 6 fuel price is reduced. TURN recommends using DRA's formula, which would produce a Number 2 fuel oil price of $.374/therm for Number 2 fuel oil, using DRA's crude oil forecast price of $17 per barrel.

Since we have adopted DRA's forecast price of $17 per barrel for Number 6 fuel oil, we will adopt the corresponding price of $.374 per therm for Number 2 fuel oil.

c. Customer Growth

Both DRA and PG&E use econometric models to forecast customer growth in all major customer classes. The results from these forecasts are included in the econometric throughput model. Differences between their estimates are less than 1%. Since the differences are so small, we will adopt PG&E's estimate.

d. Effects of Demand Charges

PG&E's DA model did not assume that demand charges would affect customer choices regarding whether or not to switch to

alternative fuels. A number of parties criticized the model for this omission.

DRA, CIG, and TURN argue that customers will surely consider these "exit costs" in their fuel switching decisions. Customers do not have infinitely long time horizons, as PG&E assumes. Instead, the model should assume a shorter term planning horizon. CIG points to PG&E's testimony to argue that demand charges have the effect of increasing a customer's alternate fuel price.

Similarly, CPG and Salmon/Mock criticize the omission of demand charges as one variable which would influence switching decisions. DGS goes further to suggest that each of the major gas utilities be required to submit a methodology for incorporating demand charges in future forecasts.

CIG proposes, based on a review of PG&E's contracts, that exit costs averaged $.03 per therm in 1989. For default agreements, estimated exit costs would be about $.05 per therm. CIG proposes that these amounts be added to the cost of alternate fuels in the DA model. CIG also supports TURN's methodology as a sound alternative. TURN would apply half of the D-1 charge plus all of the fully ratcheted D-2, at 100% load factor.

In response, PG&E states that the DA model does not calculate load loss; it calculates discounts necessary to retain load. In addition, PG&E argues that including exit charges as an assumption in the DA model is inconsistent with the way rates are negotiated with customers because transport rates are based on estimates of alternate fuel prices plus a premium.

According to PG&E, incorporating demand charge effects in a one-year test period is a difficult task. PG&E's assumption that customers look at gas use as an annual decision is most reasonable. PG&E states that it would like to study the CIG and TURN proposals.

Prudent decision-makers, when faced with a prospective fuel choice decision, should consider only <u>prospective</u> costs, not costs already incurred. Since already-incurred costs must be paid no matter what the fuel choice decision, they favor neither one choice nor the other, and so should be ignored in comparing prospective fuel costs. Since exit costs are by definition already incurred, we believe that in a world of perfect information and ideal decision-making oil prices should not be adjusted to include gas system exit costs in forecasting non-core throughput and revenues.

Our gas industry structure is still relatively new. As with several difficult questions in this ACAP, experience will eventually settle for us the proper treatment of exit costs. We will simply observe the behavior of customers operating under our new gas structure. For the present proceeding, however, we must choose between our belief that rational customers will view exit costs as sunk and the claim by TURN, CIG, and DRA (among others) that in the real world customers <u>do</u> consider exit costs in making fuel purchase decisions.

The balance of the record before us convinces us that the conservation approach is for us to include exit costs in our forecast for the present and invite testimony on this issue for the next ACAP.

We will adopt CIG's recommendation to add $.03 per therm to the cost of alternate fuels for volumes associated with negotiated contracts and $.05 per therm to the cost of alternate fuels for volumes associated with default agreements. Weighting these amounts according to usage, the adjustment to the model is $0.044. While this method provides only a rough proxy of exit costs, it is a conservative estimate which assumes customers make choices on an annual basis.

e. <u>Gas Premium</u>

The DA model includes a premium for gas to reflect its value to customers relative to the value of alternate fuels.

PG&E requests that the $.02 per therm premium on gas, adopted in D.87-12-039, be reduced to $.017 per therm. PG&E states that it has made this assumption because of changed customer perceptions with regard to service reliability, caused by curtailments last winter on the Southern California Gas Company (SoCal) gas system.

DRA, DGS, CIG, and TURN recommended against this change. DGS points out that the PG&E witness testified that lowering the premium creates a perception of shortage among customers, even though PG&E does not anticipate curtailments. Thus, the reduced premium is a self-fulfilling prophecy.

PG&E also proposes eliminating the premium assumed for GC-2 customers whose contracts expire in 1989. This change is reasonable, according to PG&E, because it expects some resistance from these customers as they realize the impact of higher rates resulting from this ACAP.

DGS argues that this change is inappropriate because the premium is set to reflect the value of gas over oil in all circumstances.

We will not change the premium since PG&E has not demonstrated that the existing amount is unreasonable. We are not convinced that customer perceptions regarding reliability have changed. In addition, we believe the premium should be assumed for GC-2 customers after expiration of their contracts. The DA model and ET model are designed to capture the effects of higher rates on the attractiveness of gas. Eliminating the premium results in double-counting necessary discounts to customers.

f. <u>Effects of Core Election</u>

TURN is critical of the DA model because it does not weight core and noncore gas prices to reflect the fact that large users may buy gas at either core prices (as core elect customers) or noncore gas prices. Without this weighting, the model will predict that discounting will be required to keep customers on the system who already realize a rate below the noncore WACOG.

DRA agrees with TURN that the DA model ignores core election even though approximately 55% of industrial throughput is estimated to be core elect. This oversight, according to DRA, is a transparent attempt by PG&E to lower its risk by ignoring what it expects to occur during the forecast period.

Like TURN, DRA proposes the DA model recognize the effects of core election by way of one of two model adjustments. The model could incorporate a weighted average of core and noncore portfolio prices. Alternatively, the model specifications could be changed so that in calculating each customer's bill, either the core or noncore WACOG would be used depending upon whether or not the customer is a core-elect customer. DRA states that the latter option may be difficult to accomplish in this case because of time constraints.

CPG and Salmon/Mock support DRA and TURN's position on this issue.

PG&E responds that the DA model should use a single benchmark price in order to avoid having the noncore transportation revenue responsibility depend on customer procurement choices. PG&E states that in some cases the core WACOG may be above the noncore WACOG, increasing the revenue allocation to the noncore.

We agree with DRA and TURN that the DA model should reflect the fact that some noncore customers elect core status. The effect of using PG&E's assumption does not exclusively affect revenue allocation between classes as PG&E seems to assume. It also affects the amount of risk allocated between shareholders and ratepayers as it affects revenue estimates from the noncore class. Incorporating DRA's and TURN's proposal would provide a more realistic estimate of noncore revenue. PG&E also states that alternative approaches would not comply with the Commission's stated goal of keeping transport and procurement rates independent of each other. We do not agree with PG&E that the effect of making this forecast model adjustment would be to change service arrangements for transport and procurement. PG&E confuses forecast assumptions with actual changes in rate structures.

We will adjust the DA model to incorporate adopted estimates of core elect throughput. A more extensive change in model specifications, as DRA suggests, may be appropriate in future ACAPs.

3. Throughput Estimates

Throughput estimates include all gas, whether procured by the utility or the customer, transported through utility pipelines. Throughput estimates affect rates: the higher the estimate of throughput, the more volumes over which to spread fixed costs. Throughput estimates also affect the level of risk borne by the utility: higher estimates increase the risk of revenue recovery.

a. Industrial

Using its ET model, PG&E estimated industrial throughput for the test period to be 1,231 MMth. The difference between DRA's and PG&E's estimates of industrial throughput is about 13.5%. This difference is mainly due to differing model specifications regarding demand elasticity and DRA's higher estimate for fuel oil. PG&E argues that DRA's elasticity assumptions are unrealistic because industrial demand has not increased at a proportionately higher rate than industrial growth in recent years.

DRA estimates a 1.5% increase in throughput for a 1% change in industrial activity. PG&E estimates a .9% increase in throughput for a 1% increase in activity.

TURN challenges PG&E's industrial throughput estimates. TURN points out that PG&E's forecast of 1,231 MMth is substantially below its 1988 year end projection of 1,591 MMth and follows a steady increase in load since 1986. TURN argues that model assumptions and specifications, discussed in more detail below, systematically underestimate throughput by at least 30 MMth, in addition to other model shortcomings.

DGS asserts that PG&E incorrectly assigns all cogeneration gas use to the G-COG rate. PG&E admits that the G-COG tariff currently limits gas sold under the G-COG rate to 9,300 Btu per kilowatt-hour (kWh). DGS' witness testified that the average cogeneration project uses about 10,250 Btu per kWh or 30 MMth per year, which DGS proposes should be assigned to the G-IND rate. This 30 MMth per year should be subtracted from the G-COG unadjusted throughput and added to the industrial unadjusted throughput since that gas would be sold under the G-IND rate. The incremental cogeneration calculation does not require this correction, according to DGS. TURN makes the same proposal.

TURN also notes that PG&E incorrectly attributed half of cogeneration usage to gas needed to generate steam. TURN points out that DGS' witness testified that about 30% of cogeneration gas is used for industrial uses. Accordingly, TURN recommends the difference of 104 MMth be added to industrial throughput.

With regard to DGS' proposed 30 MMth cogeneration adjustment, PG&E replies that DGS failed to subtract out the cogeneration volumes which are GC-2 loads. The result would be a total adjustment of 18 MMth.

We will not rule on values for demand elasticity since demand elasticity is a product, not an input, to the econometric model. They are determined according to various model assumptions. In general, we will use PG&E's specifications for the econometric model, modified by changes in inputs and assumptions as discussed elsewhere in this order. We will also make the adjustments to the industrial throughput and cogeneration throughput forecasts recommended by TURN and DGS, except that we will subtract 18 MMth from that adjustment to reflect PG&E's correction. The adjustments provide a more accurate forecast. The adopted industrial throughput will also be adjusted for changes in other inputs and model specifications presented elsewhere in this order.

b. Utility Electric Generation (UEG)

PG&E estimated UEG throughput exogenously as 1,387 MMth for the test period. This estimate is based on average hydro year conditions.

DRA accepts PG&E's estimates for PG&E's own UEG throughput as consistent with the assumptions adopted in its recent Energy Cost Adjustment Clause (ECAC) proceeding. DRA's estimate for SCE throughput is 933 mega-decatherm higher than PG&E's. DRA based its forecast on the results of its production cost model run in the latest SCE ECAC proceeding.

TURN recommends using the forecast adopted in the current ECAC proceeding, at least for the first seven months of 1989. TURN believes the data in the ECAC has been more fully scrutinized in ECAC hearings than it could have been in this proceeding.

TURN also proposes that the Commission adopt a provision to reflect increased UEG gas usage occurring as a result of a shutdown of Rancho Seco. TURN's proposal provides for an alternative gas cost allocation if the plant is shut down so that non-UEG customers are protected from the vagaries of electric resource availability. A similar mechanism was adopted in PG&E's most recent ECAC order.

PG&E responds that the UEG forecast proposed by TURN reflects dry hydro conditions of 1988 for the first five months of the forecast. PG&E points to D.87-12-039, which stated that UEG forecast should be based on an average hydro year.

We agree with DRA that ECAC expense estimates should be used to the extent they are current, and that they should be updated using methodologies adopted in ECAC proceedings. Estimates, however, should continue to be based on an average hydro year, as we stated in D.87-12-039. Accordingly, we will adopt

DRA's estimates of UEG throughput since they are consistent with PG&E and SCE's ECAC review estimates and methodologies.

SCE proposes that its Cool Water plant be classified and treated as a UEG plant in this proceeding because it produces electricity, not industrial products. PG&E has provided no justification for treating Cool Water as an industrial plant. PG&E responds that since Cool Water is a combined cycle plant, the plant is unlike any of PG&E's electrical plants. PG&E states that SCE is able to negotiate rates like any other customer if it is dissatisfied with the UEG rate.

We will not grant SCE's request to reclassify Cool Water at this time. The scope of this proceeding does not anticipate such customer reclassifications. SCE is an able negotiator and has the opportunity to negotiate its gas rates with PG&E if it is dissatisfied with PG&E's industrial rates.

As to TURN's proposal for a reallocation of fixed costs during Rancho Seco shutdowns, we will not further complicate the ACAP proceeding with another allocation mechanism unless it is truly warranted. We are especially hesitant to undertake a twice-yearly allocation process. Some risk of a mismatch between forecasted and actual values is expected. The risk of misallocation because of unanticipated Rancho Seco shutdowns, however, is not great enough to make the program change proposed by TURN.

c. Enhanced Oil Recovery (EOR)

PG&E estimates, based on market information rather than an econometric model, a large reduction in throughput to the EOR market as a result of lower oil prices. For 1989, PG&E estimates 232 MMth of EOR throughput.

DRA states that PG&E's original estimate of 373 MMth is reasonable. TURN agrees with DRA that the original estimate is reasonable on the grounds that PG&E's lower forecast resulted from lower priced oil. If the Commission adopts a crude oil price of $17 per barrel, EOR throughput should be estimated at 373 MMth.

PG&E responds that its original estimate was based on an oil price considerably higher than DRA's oil price estimate of $17. DRA acknowledges that EOR throughput is a function of oil prices and defends its higher throughput estimate on that basis.

We will adopt DRA's proposal since we have adopted DRA's oil price estimate.

d. Interutility

PG&E's updated filing assumes 202 MMth per day (or 53 million cubic feet (MMcf) per year) of interutility transport. Its estimate assumes that no gas will be sold off-system by PG&E to Southern California customers from PG&E's noncore portfolio at the noncore WACOG. PG&E bases its estimate on 1988 off-system transport volumes which averaged 42 MMcf per day, not including interutility transport of customer-owned gas.

DRA supports PG&E's original estimate of 673 MMth (or 176 MMcf per day) on the grounds that the recent large reduction in interutility throughput occurred as a result of the drop in oil prices which are again increasing. DRA states that if its oil price estimate of $17 is adopted, the original PG&E interutility transport estimate should also be adopted. TURN supports DRA's position.

Based on our findings regarding gas prices, oil prices, and their interrelationship, we will adopt DRA's forecast of 673 MMth for the test period.

e. Residential and Commercial

PG&E and DRA estimates of residential and commercial throughput are very close. Our adopted estimates of residential and commercial throughput are determined according to changes in model specifications and assumptions determined elsewhere in this order.

f. Cogeneration

PG&E developed its estimates of cogeneration throughput exogenously by adding throughput from projects it expects to come on line during the forecast period to recorded December 1987 cogeneration usage.

As discussed under the discussion of industrial throughput, PG&E's estimate of cogeneration throughput will be adjusted to reflect the changes proposed by DGS and TURN. With these adjustments, we will adopt PG&E's estimate of cogeneration throughput.

B. Cost of Gas

1. Effects of Oil Prices on Gas Prices

A major controversy arose during the proceeding regarding the relationship between oil and gas prices. PG&E estimated that the cost of oil would significantly decrease during the forecast period, making oil a more attractive alternative to noncore customers and thereby reducing gas throughput estimates. PG&E did not assume gas prices would fall as a response to the lower cost of alternative fuels.

DRA, TURN, CIG, Salmon/Mock, CPG, and DGS argued that the cost of gas is influenced substantially by the cost of oil and other alternative fuels.

CIG's witness testified that a reduction in oil prices puts pressure on gas prices as users switch to fuel oil. The estimated reduction of crude oil prices to $14.62 should force spot gas prices at the California border down to $1.88 per MMBtu, in contrast to PG&E's estimate of $2.20 per MMBtu. CIG arrived at its estimate by applying a "rule of thumb" used by energy forecasters to equate the cost of oil to the cost of gas. CIG also applied a DRI energy forecast model to check its estimated cost of gas.

CIG observes that the relationship between gas and oil prices has historically not been a precise 10:1 ratio. Rather, on average, the ratio represents a reasonable equilibrium relationship.

CPG agrees that it is wrong to assume there is no relationship between gas and oil prices, although it does not support CIG's use of a 10:1 ratio. CPG urges the Commission to use a "rule of reason" rather than a "rule of thumb" and not be constrained between the extreme proposals of PG&E and CIG.

DGS proposes that the Commission consider a six-month forecast twice a year, since the volatility of oil prices increases risks to customers and the utility. Alternatively, the Commission should assume at least that gas prices do follow oil prices to some extent.

TURN also challenges PG&E's assumption that gas prices will not fall in response to lower oil prices. The major objective of industry restructuring is to promote competition among gas supplies and between gas and oil suppliers. It is counterproductive to assume that every dip in oil prices must be matched by a discount in utility gas prices, and gas producers will not drop their prices if PG&E will absorb necessary discounts for them. PG&E's assumptions, according to TURN, may result in a self-fulfilling prophecy which will work to the detriment of all California gas consumers.

In response, PG&E criticizes CIG's gas cost estimate by arguing that the "rule of thumb" is not a refined method for estimating future gas prices and that DRI does not rely on such ratios. PG&E points to CIG witness' testimony that the 10:1 ratio has not held up historically and that DRI does not use such ratios in its forecasts.

Much debate centered on whether CIG's estimated wellhead prices included the El Paso gathering charge of $.34. PG&E argued that they did not, and showed that when the $.34 gathering charge is added to CIG's price estimate, that estimate exceeded PG&E's. CIG responded that its wellhead price did include gathering costs.

On brief, CIG noted that if the Commission adopts CIG's throughput forecast methodology, the Commission need not determine forecasted oil and gas prices. The output of PG&E's models requires such determinations. Since the models are, according to CIG, unreliable forecasting tools, there is no reason to forecast specific gas and oil price levels.

We agree with the parties who propose that a significant reduction in oil costs is likely to result in lower gas prices. Our new regulatory framework is based in large part on an assumption that competition between alternate fuels exists. PG&E's own case makes that assumption. Where such competition exists, price changes occurring for one product are likely to affect prices of substitutes. While no consistent historical relationship between oil and gas is apparent, it is clear that oil prices affect gas prices over time. Industry experts agree that this relationship exists. Our determinations of gas price forecasts in the following discussion will be made with this relationship in mind.

We are surprised that PG&E has refused to recognize such a relationship in this proceeding. Assuming lower forecasted oil prices, PG&E's assumptions regarding gas prices for the forecast period are unrealistic.

2. <u>Core WACOG</u>

The core portfolio contains all long-term supplies and any short-term supplies needed to meet demand. In this application, PG&E estimated its core portfolio WACOG to be $1.92 in 1989. DRA estimated the core WACOG to be $1.87.

Much of the debate regarding gas costs centered around prices for gas from California sources and Southwest suppliers, which together make up about a quarter of total supplies. Overall, DRA does not expect the price of short-term supplies to increase during the forecast period. PG&E expects increases for California and Southwest supplies. Appendix B, Table 3 provides our adopted forecasts of gas prices and volumes from various supply sources.

a. California Supplies

PG&E estimates California supplies will average $1.85/MMBtu during the test period based on the price it is currently paying for small volumes of California gas. DRA believes California supplies will average $1.70/MMBtu, which is the present negotiated price for California gas. DRA does not believe California gas prices will rise as a result of upcoming contract negotiations with California supplies, given the fall in oil prices.

TURN states that PG&E's estimate is probably inevitable, given the recent legislative intervention into PG&E's relationship with California producers.

Salmon/Mock supports the PG&E estimate on the grounds that PG&E has already negotiated an increased price with some producers and because PG&E currently intends to offer an increased price of $1.85/MMBtu to all California producers.

Since PG&E is already paying $1.85 MMBtu for some gas, we will adopt that amount as a reasonable estimate of prices for California gas.

b. Rocky Mountain Supplies

PG&E estimates Rocky Mountain supplies will be $1.67/MMBtu. DRA accepts PG&E's price and volume estimates. CIG proposes a Rocky Mountain price of $1.35/MMBtu, based on its analysis of the effects of oil prices on gas prices. We will adopt a price of $1.67/MMBtu because it is the rate currently on file with the Federal Energy Regulatory Commission (FERC).

c. El Paso Supplies

There is no dispute with PG&E's assumption that El Paso supplies will be too expensive to be purchased economically during the test period. We will not assume any supplies from El Paso during 1989.

d. PGT Supplies

PG&E estimates a border price of $1.847/MMBtu, which is the rate in the currently effective PGT general rate case before FERC. DRA concurs with this estimate. CIG proposes a Canadian price of $1.61/MMBtu, based on its forecast of falling gas prices generally.

Since the record was submitted in this case, Canadian producers filed an application with the Canadian National Energy Board (NEB) to increase the commodity rate to $1.90/MMBtu. The NEB approved the rate on a temporary basis. We do not expect this rate to go below $1.90/MMBtu, since some producers are seeking a higher price and PGT has accepted the $1.90/MMBtu price. We will take official notice of NEB ruling and adopt $1.90/MMBtu, adjusted to $1.94/MMBtu at the California border, for the Canadian gas price.

e. Southwest Supplies

PG&E estimates the cost of Southwest supplies to be $2.20/MMBtu during the test period. DRA estimates Southwest supplies will average $2.03/MMBtu, which is the average price during the period October 1987 through September 1988. DRA bases its estimate, in part, on DRI forecasts which predict an almost equal probability of a slight rise in oil prices and a sharp decrease in oil costs. Following PG&E's divulging some price information in its contract with ENRON, DRA modified its estimate upward to $2.13/MMBtu.

PG&E criticizes DRA's estimate because it assumes 1987 prices will remain constant through 1990 and fails to take into account El Paso's general rate case.

Similarly, Salmon/Mock believes DRA's estimate is too low given that 50% of PG&E's Southwest supplies will be purchased under long-term contracts at $2.30/MMBtu.

DRA responds that the effects of the El Paso rate case cannot be inferred from PG&E's data. To this, TURN adds that the El Paso rate increase is subject to refund, and that it is wrong to assume that gas purchasers, as opposed to producers, will bear all of the increase. TURN also adjusted its estimate of Southwest gas prices--to $2.15/MMBtu--after PG&E presented information about its long-term agreements.

Half of PG&E's Southwest gas is purchased at $2.30. Consequently, the average price of Southwest supplies would be $2.20/MMBtu if the other half of the supplies averaged $2.10 MMBtu. We find this amount high for spot gas given world oil prices. We also agree with TURN that the effects of the El Paso rate increase should not be assumed to fall entirely on purchasers. We will assume an average price for Southwest gas of $2.10. This amount assumes that Southwest spot prices will be, on average, $1.90.

f. Volumes from the PGT Line

Significant controversy arose during the hearings regarding capacity on PG&E's interstate lines. PG&E estimates Canadian gas takes of 878 MMcf/day (or 320 Bcf per year) in 1989, an amount significantly below total capacity and considerably less than actual throughput in 1988. These estimates result in higher total gas costs since Southwest gas is more expensive than Canadian gas.

DRA, Salmon/Mock, TURN, CPG and CIG argue that PG&E is underestimating the volume of takes on its PGT line and overestimating those from the El Paso line.

CPG agrees that reduced throughput over the PGT line could occur if PG&E's throughput estimates are adopted. It argues, however, that constraints which would block full utilization of PGT's capacity under any scenario have not been demonstrated. CPG points out that PG&E has, in the pending PGT rate case at FERC, stipulated to an estimate of 1,000 MMcf/day, well above PG&E's estimate in this case. CPG also comments that PG&E should have a special burden to demonstrate that it cannot carry greater volumes over the PGT line given its pending proposal at the CPUC to expand its existing system.

DGS also points out that PG&E is ignoring the PGT rate case, and that PG&E is currently operating the PGT pipeline at full capacity. The Commission, according to DGS, should assume that the PGT pipeline will operate at full capacity year round.

Salmon/Mock agrees that PG&E has not provided evidence to demonstrate that it cannot operate the PGT line at full capacity. Salmon/Mock proposes that the Commission adopt a forecast which allocates 60 MMcf/day for noncore customers in the northern portion of PG&E's system and 60 MMcf/day of interutility transportation of Canadian gas for customers in southern California, in addition to the 878 MMcf/day forecast by PG&E.

PG&E responds that it cannot increase PGT takes without reducing below minimum capacity levels the takes from the El Paso line. PG&E also states that at higher volumes estimated by DRA, it must pay higher commodity costs for PGT gas because of increased compressor fuel usage.

We agree with the parties who argue that PG&E has not demonstrated why it can transport less than the maximum capacity over the PGT line during the test period. PG&E's witness testified that average deliveries on the PGT line were 1,009 MMcf/day during January through November 1988. PG&E forecasts no transport of Canadian gas over the PGT pipeline in 1989, and Canadian gas is less expensive than Southwest gas. We also note that PG&E has stipulated to forecasts of full capacity over the PGT pipeline in the PGT rate case. Accordingly, we will adopt an estimate of 1,009 MMcf/day of Canadian gas over the PGT pipeline for the test period.

3. Noncore WACOG

As we determined in D.87-12-039, the noncore portfolio contains only short-term supplies with prices that are firm for up to 30 days. PG&E estimated a noncore WACOG of $2.20 per MMBtu for 1989, mainly on the basis of estimates of Southwest gas spot prices.

DRA forecasts a noncore WACOG of $1.97 based upon a 12-month historical average of spot prices at the California border provided in the reports of Natural Gas Week. DRA states PG&E's estimate relies too heavily on recent winter prices, which tend to be higher than average annual prices. As discussed above, DRA states the effects of the El Paso rate case on Southwest supplies cannot be inferred from PG&E's data. TURN supports DRA's position.

CIG estimated the noncore WACOG to be $1.82 for reasons presented in the previous section on the effects of oil price changes on gas prices.

We will adopt a noncore WACOG of $2.20, consistent with recent trends in the spot market.

4. Transition Costs

In D.87-12-039, we determined that transition costs are those which:

- o Took effect before December 3, 1986;
- o Were incurred for the benefit of all ratepayers;
- o Were intended to be recouped from all ratepayers;
- o Result in costs in excess of a currently reasonable level.

Among those costs recognized as transition costs are El Paso liquids, Order 94/270 costs, take-or-pay for Rocky Mountain and Canadian supplies, GEDA costs, and storage demand charges. Most transition costs were not disputed by the parties. In those cases, we adopt PG&E's estimates as reasonable. Disputed issues are discussed below.

a. Storage-Related Costs

PG&E estimates storage-related transition costs based on an annual forecast. DRA forecasts these costs based on a monthly average because storage-related costs are booked monthly on the basis of monthly core WACOGs and average industry values. DRA believes forecasting accuracy requires an estimate of seasonal spot price variations. PG&E responds that the differences in estimates are largely due to differing gas price forecasts, but that DRA's methodology is contrary to that developed in D.87-12-039 and is subject to greater uncertainty.

We agree with PG&E that we should not change our methodology at this time. We will use PG&E's approach of weighting average annual gas costs, based on the costs we adopt in this order.

b. El Paso Filings at FERC

PG&E proposes to establish an interest-bearing deferred debit account to track potential new transition costs which may result from FERC resolution of various El Paso filings. PG&E proposes that disposition of any account balances be considered in its next ACAP.

CPG agrees with PG&E's proposal to defer resolution of this issue until after FERC's ruling is final. TURN argues that PG&E should not be granted interest for these extraordinary costs. DRA does not take issue with PG&E's position but notes that the quantification and method for recovering take-or-pay obligations will become highly controversial when they are known.

We will adopt PG&E's proposal to establish a deferred debit account, with interest, which will be considered in PG&E's next ACAP.

5. EOR and GC-2 Revenues

PG&E estimates $4.1 million credit from the EOR market. DRA's forecasts $6.9 million, mainly as a result of differing EOR forecasts. PG&E urges that if the Commission adopts PG&E's EOR forecast, it should adopt its EOR credit.

TURN points out that PG&E's revenue estimates do not include escalation rates which are included in contracts with EOR and GC-2 customers.

Because we have adopted DRA's estimate of EOR throughput, we will adopt DRA's associated forecast of EOR credits in the amount of $6.9 million. We agree with TURN that a more accurate estimate of EOR and GC-2 revenues would include escalation factors. We will adjust the EOR and GC-2 revenues using escalation factors of 3.4% and 3.738%, respectively, and expect PG&E to present escalated numbers in the future.

C. Cost Allocation

Cost allocation is the process of assigning fixed and variable costs to various customer classes. PG&E's core customers include residential, small commercial, and large commercial customers. The remainder, including industrial, UEG, cogeneration and wholesale customers, are noncore customers.

1. Variable Costs

The primary variable cost to PG&E is the cost of gas. Under the Commission's new regulatory framework, large customers may elect to purchase gas directly from suppliers or brokers and have PG&E transport the gas. Alternatively, such customers may continue to purchase gas from the utility at tariffed rates, which may change every two weeks to reflect price and market changes.

Core prices, on the other hand, do not change frequently to reflect changes in gas costs. PG&E accounts for differences between rates and costs in its Purchased Gas Adjustment Account (PGA), a balancing account which relieves PG&E of any risk associated with core gas costs.

PG&E proposes, and DRA concurs, that PGA account balances should be allocated on an equal-cents-per-therm basis to both core and core elect customers.

PG&E's proposed treatment of PGA balances is consistent with our previous orders and will be adopted.

2. Fixed Costs

Fixed costs are those which are relatively stable and are generally incurred notwithstanding the volumes of gas flowing through the utility's system. PG&E is at risk for any mismatch that occurs between noncore costs and rates except in the case of certain levels of NRSA balances which are recoverable for two years following implementation of our program.

In D.86-12-009 and subsequent orders, we established cost allocation principles for PG&E's fixed costs. PG&E does not propose any changes to adopted methods for allocating fixed costs. Such costs include those associated with distribution, transmission, storage, and administrative and general expenses.

a. Negotiated Revenue Stability Account (NRSA) Balances

The NRSA tracks recovery of revenues associated with fixed costs allocated to the noncore market. As of November 1988, the NRSA balance was zero. During periods when the balance is negative, PG&E proposes that NRSA undercollections be allocated on an equal-cents-per-therm basis to all customer classes. It uses this method because its result approximates the same result that would have occurred had the original estimates of revenues and expenses been correct.

DRA proposes that they be based on an equal percentage of fixed cost revenue. DRA makes this recommendation because the Commission has traditionally used such an allocation method for fixed cost underrecovery. DRA believes the equal percentage of fixed cost allocation approximates the rate structure that would have resulted if noncore throughput had been correctly forecast. It also mitigates the destabilizing effects of increasing large customer rates.

DGS supports DRA's proposed allocation since it mimics the actual cost allocation which would have occurred if the demand forecast had been correct.

CIG proposes that NRSA balances be allocated only to core customers. To allocate these balances to the noncore will only exacerbate the problem that created the undercollection. As a matter of fairness, the NRSA balance should not be allocated to the noncore because those who will end up paying for it will be default customers: other noncore customers will be able to negotiate around it.

TURN recommends that the entire balance be initially allocated to the noncore market on an equal-cents-per-therm basis. TURN argues that the DA model will end up allocating certain fixed costs to core customers anyway, and noncore customers will never pay more than their value of service. It would be unfair for core customers to pay noncore fixed costs through the allocation of NRSA balances and through the discount adjustment process, especially when the costs involved were originally allocated to the noncore class. TURN also argues that core fixed costs are allocated only to core. As a matter of fairness TURN believes the entire NRSA balance should be allocated to the noncore.

We will allocate all NRSA balances to the noncore, as TURN suggests. We believe this allocation is fair because we have allocated all core fixed cost balances to the core. By so doing, we do not change allocations between the core and noncore.

b. <u>Take-or-Pay Transition Costs</u>

Take-or-pay transition costs are allocated on an equal-cents-per-therm basis and are recovered through volumetric rates. In D.87-12-039, we recognized that the potential magnitude of these costs could require alternate treatment.

In this case, these costs are very small. Accordingly, we will continue the current method of recovering them.

3. <u>EOR Revenues</u>

PG&E proposes to allocate EOR revenues by an equal percentage of base fixed costs or margin. As DRA points out, we required, in D.87-12-039, that such costs be allocated on an equal percentage of fixed costs, that is, base costs plus pipeline demand charges. We will not change this allocation principle at this time.

4. Cogeneration Shortfall Account

a. Allocation of Undercollections

The Cogeneration Shortfall Account (CSA) is a balancing account established to account for a revenue shortfall occurring when cogenerators pay less than the average UEG rate because their otherwise applicable rate is temporarily lower. There is no undercollection in the CSA at this time.

PG&E recommends allocating CSA balances to all customers. DRA and CCC object to this allocation and point out that the Commission, in D.87-05-046, directed that shortfalls should be distributed to the UEG class to promote efficient production of electricity and on grounds of equity.

TURN proposes elimination of this account on the grounds that it provides too much protection to the utility. If it is not eliminated, TURN proposes that undercollections be recovered from UEG and cogeneration customers.

SCE supports PG&E's proposal on the grounds that this "subsidy" to cogenerators is based on the presumed benefits of more efficient overall gas usage through the cogeneration process. Since those benefits accrue to all customers, all customers should pay the subsidy.

We will adopt DRA and CCC's recommendation to allocate shortfalls to the UEG class for the reasons we adopted this practice in D.87-05-046. In response to SCE's comments, we believe it more appropriate to price services based on cost in order to send appropriate signals regarding use rather than to allocate costs on the basis of incidental and widely dispersed benefits of a technology.

We will not eliminate this account at this time, as TURN suggests. However, we believe that as PG&E's competitive posture improves under our new regulatory program, it may be appropriate to eliminate this and similar accounts designed to protect the utility during this transition period.

b. Proposed Accounting Change to CSA

PG&E requests that the Commission approve a modification to the CSA. Under its proposal, PG&E would book the difference between revenues at the adopted average UEG rate and the average rate actually paid. Under existing practice, PG&E books the difference between cogeneration revenues at the actual UEG average rate and the otherwise applicable schedule, whenever the latter is lower.

PG&E argues that the current accounting method leads to a shortfall because of differences between forecasted revenues and actual revenues occurring due to weather. Under our rules, cogenerators may purchase gas out of either UEG tariffs or otherwise applicable rates. During a dry year, rates for the UEG class fall below those forecasted (because demand is higher and fixed costs are spread over larger volumes than expected). When UEG rates are lower than other rates applicable to cogenerators, those customers use the UEG rate, leading to a shortfall from them.

PG&E forecasts that it will lose about $5.0 million between May and December 1988 as a result of this effect. Accordingly, PG&E requests that the Commission "smooth the year-to-year effects of the adopted cost allocation and rate design policies on cogeneration gas transportation revenues" which occur because of weather. In the alternative, PG&E states forecasting QF gas prices would take care of the problem. This approach is being discussed between PG&E and QFs.

Other parties to the proceeding object to PG&E's proposal. TURN points out that during a dry year, PG&E may lose revenues from cogenerators, but its revenues from UEG customers increase. DRA objects to the proposal because the modification would reduce risk to PG&E and increase risk for its ratepayers. According to DRA, PG&E is already protected from underrecovery of noncore revenues by way of the NRSA account and that potential losses during some years would be offset during others. PG&E

should not be granted increased regulatory protections six months after the new program has been put into place. CCC and DGS also oppose PG&E's proposal.

We will not adopt PG&E's proposal. We agree with DRA and TURN that the modification effectively shifts risk from PG&E to core customers. The risk PG&E currently bears for a cogeneration shortfall is not excessive and is offset by potential gains from UEG customers during a dry year. Further, the probability of losses in some years is offset by the probability of gains in others.

We remind PG&E that our program was developed to provide improved incentives for efficiency for PG&E and additional opportunities to benefit from competition. Increased protections in gas markets will only be granted where significant harm would otherwise result to shareholders or ratepayers. Whether QF gas prices are based on a forecast is an issue which may be considered in other Commission proceedings and we need not address it here.

5. Oil Burn Credit for Cogenerators

DGS proposed a mechanism to address the effects of economic oil burns on cogeneration rates. Under current policy, PG&E switches from gas to oil whenever oil is cheaper than the incremental cost of gas (even though oil may be more expensive than the core WACOG). As throughput drops, cogeneration gas rates increase to reflect the higher UEG rates from two months previous.

DGS proposes that during months when economic oil burns occur, the cogeneration gas rate should be developed by dividing gas fixed costs by throughput including both gas and oil burned for economic reasons. According to DGS, such a mechanism would put cogenerators in the same position as they would be in if PG&E operated under a "two-company" policy. Under a two-company policy, PG&E would burn oil only when the oil price was less than the core-elect WACOG, resulting in fewer oil burns.

PG&E objects to DGS's proposal on the grounds that the Commission has recognized that the actual average rate paid by UEG customers (and therefore cogeneration customers) will vary monthly according to many factors, including weather conditions. DGS' proposal, according to PG&E, is one-sided and insulates cogenerators from one factor that can increase their rates. If UEG rates are higher than otherwise applicable rates, cogenerators may switch schedules.

SCE also objects to DGS' proposal. SCE states the distortion between cogenerator and UEG rates is not due to the "one-company" policy but rather due to distortions caused by PG&E's demand charges.

We will not grant DGS' request to change accounting for economic oil burns. We developed the one-company policy because it results in the most efficient use of resources. The fact that it is not applied across companies, like Southern California Edison and Southern California Gas, does not make it unfair. The converse--that cogenerators receive a windfall from a two-company policy--could also be true. Under existing policy, cogenerators may still opt to use the otherwise applicable industrial rate when UEG rates increase.

6. Revenue Shortfalls Resulting From Reassignment of Core Customers

In Resolution G-2796, we directed PG&E to track revenue shortfalls resulting from transferring core customers to noncore status. We stated we would determine treatment of those shortfalls in this proceeding.

TURN proposes that these revenue shortfalls be shared equally between ratepayers and shareholders. According to TURN, this would give the utility the incentive to adjust its cost allocations to capture the reassignment of such customers as quickly as possible. Once such customers are treated as noncore for cost allocation, there would no longer be any ongoing impact on the core balancing account. TURN adds that the shortfall from the Stone Container Corporation contract should be borne entirely by PG&E since the Commission rejected that contract in Resolution G-2818.

PG&E believes TURN's proposal is unfair and illogical. Since revenues received from reassigned customers continue to be recorded in core balancing accounts, there is no windfall for shareholders through the noncore gas fixed cost account. Core customers are actually better off as a result of reassignment than they would have been without it because they continue to receive some revenues rather than none.

While shared losses may provide some incentive for the utility to reduce costs, we agree with PG&E that the value of the incentive is outweighed by the issue of fairness. The existing accounting treatment for customers who have transferred to noncore status is reasonable and generally consistent with our program.

D. Rate Design

Generally, the parties applied the rate design principles established in D.87-12-039. They also applied the conceptual framework for baseline rates adopted in D.88-10-062. Our final rate design is presented in Appendix C.

1. Baseline Rates

PG&E proposes to set residential rates so that the 93.7% differential between tiers is consistent with that adopted in D.88-10-062. DRA generally agrees with this rate design proposal, but recommends retaining the $.40 per therm differential between Baseline and Tier II adopted in D.88-10-062. DRA notes that using PG&E's percentage difference will result in a rate spread of about $.44, an amount the Commission rejected in its baseline order.

We will adopt DRA's proposed $.40 per therm differential as reasonable and consistent with D.88-10-062 and SB 987.

2. <u>Summer and Winter Commercial Rates</u>

PG&E proposes a 35% differential between summer and winter commercial rates. According to PG&E, this differential was adopted by the Commission in D.87-12-039, and in recognition that the actual winter/summer differential appeared to be more than 35%.

TURN characterizes this differential as "excessive", observing that PG&E apparently allocated all distribution related costs exclusively to the winter period. TURN argues that distribution facilities must be in place to serve load all year long. Accordingly, the differential in cost attributable to peak usage should be allocated as a winter-only cost component to avoid placing an undue burden on seasonal commercial customers.

DRA concurs with PG&E's method as reasonable and consistent with D.87-12-039. We will continue to use the practice adopted in that order.

3. Take-or-Pay and El Paso <u>Direct Bill Balancing Account</u>

DRA and DGS propose that existing take-or-pay costs should be collected volumetrically to encourage the utilities to negotiate the best rate with pipelines. We believe this is reasonable approach and will reflect it in our adopted rate design. Existing direct bill expenses should continue to be recovered in the demand charge, pursuant to D.87-12-039.

4. Transition Cost and Implementation <u>Balancing Account Surcharges</u>

PG&E proposes that it be permitted to discount Transition Cost and Implementation Balancing Account (TC/IBA) surcharges. PG&E believes this additional flexibility will allow it to retain load.

DRA and TURN support this proposal. DRA states that PG&E, if granted this flexibility, be required to (1) book negotiated revenue above variable and customers costs first, to implementation and transition accounts; and (2) apportion necessary discounts to all accounts pro rata so that its guarantee to eventually recover remaining balances can be scrutinized on an account-by-account basis. TURN supports DRA's recommendations. PG&E does not object to them.

We agree that the additional flexibility PG&E requests may reduce load loss. We will adopt DRA's suggestions regarding associated accounting principles.

E. <u>Revenue Requirement</u>

1. <u>Balancing Account Balances</u>

The parties agreed that we should use the latest available information regarding balancing accounts balances. On February 9, 1989, PG&E filed an update of balancing account amounts including the PGA as of January 31, 1989. The final amount is $205.2 million, which is to be amortized over one year with the exception of the core and noncore implementation balancing accounts, which are to be amortized over 16 months. The balances are presented in Appendix B, Table 6.

PG&E proposes to seasonally adjust the Core Gas Fixed Cost Account (GFCA) by forecasting undercollections as of April 1989 to mitigate a potentially large increase to core customers. DRA concurs with these proposals.

Both SCE and DGS recommend extending balancing account amortization periods if required to avoid rate shock. In addition, DGS believes the Commission should provide a 45-day period before implementing new rates in order to allow customers to respond in advance to increased rates. CIG proposes a grace period of four months. PG&E states there is no justification for this delay beyond the self-interest of the parties proposing it.

The only other controversy regarding balancing account amounts concerned the CFA. DRA challenged PG&E's estimate for the allowance for doubtful accounts, recommending a $3.6 million adjustment to the CFA. PG&E has agreed to the adjustment, and we have reflected this in the updated balancing account balances.

We will not adopt proposals by DGS and CIG to defer rate implementation. The effect of that would be to put further upward pressure on rates in the subsequent period. Additionally, large customers should be able to respond quickly enough to higher rates if it serves their interests. Those customers have had an opportunity to plan for rate increases since September 1988 by way of PG&E's customer notice.

Since balancing account balance undercollections are not large, we will amortize them with the exception of CIBA and NIBA balances over a one-year period, which is our usual practice. CIBA and NIBA balances will be amortized over 16 months.

2. <u>1989 Attrition Year Revenue Requirement</u>

PG&E requested that its base revenues in this filing be updated to reflect 1989 attrition year revenue requirement adopted in G-2838. The parties did not object. PG&E's gas revenue requirement for 1989 was increased $37.18 million by Commission Resolution G-2838. The total gas revenue requirement adopted in this proceeding is updated to reflect these attrition year adjustments.

3. <u>Total Revenue Requirement</u>

PG&E's modified 1989 ACAP application requests a total gas revenue requirement of $2,656.7 million, which does not reflect 1989 attrition changes or updated balancing account estimates. Our adopted revenue requirement based on the findings made above is $2,821.2 million and is presented in Appendix B, Table 6. This reflects the 1989 attrition changes and balancing account balances as of January 31, 1989.

F. <u>Other Matters</u>

1. <u>Notice Requirements</u>

TURN notes that PG&E's total revenue requirement increased substantially in its amended filing, but PG&E did not notify its customers of that increase. TURN states the Commission has consistently refused to grant a revenue requirement higher than that noticed to customers, and suggests that the Commission continue to follow that policy.

DRA agrees that PG&E should have amended its application and noticed that change. DRA notes that the exception to the rule is a case where increase in expenses results from updated balancing account balances. In this case, forecast assumptions--not balancing account expenses--changed.

PG&E responds that its notice includes reference to the fact that the rates adopted by the Commission may be higher or lower than those requested.

In this case, we do not need to rule on the notice issue since we authorize a revenue requirement increase for PG&E less than the amount shown in its original notice. We have, in this order, directed PG&E to refrain from late-filed changes to its application in future proceedings except in unusual cases. If it does increase its rate request following the original notice, we will at that time consider whether additional notice is required.

2. Proprietary Information

A number of parties objected to PG&E's use of proprietary data in this proceeding. DGS suggested that PG&E's refusal to disclose information used as inputs to its models was "arrogant" and future proceedings should not permit use of "black box" ratemaking.

TURN suggests that PG&E should be required to include in its workpapers complete documentation of any computer models used in preparing the company's case, consistent with AB 475 and in order to preclude the time-consuming process of discovery which arose in this case. TURN also criticizes PG&E's use of a confidential assessment of willingness-to-pay. The confidentiality of this information, according to TURN, has lead to discovery problems in this proceeding. Finally, TURN also states that relying upon PG&E to run the model--because Commission staff cannot run the model independently--is cumbersome and creates the appearance of impropriety. DRA generally supports TURN's comments.

We are currently considering general rules regarding access to computer models in I.88-04-030. These rules will address access to models in future ACAPs.

3. Updated Information

The parties generally agree that the most recent balancing account balances should be reflected in the Commission's final order. PG&E had also requested an opportunity to update forecast information. During hearings, a number of parties objected to this updating. DRA points out that updating contested issues after the conclusion of hearings would make the hearing process meaningless. We agree with that assessment and will not entertain updates of contested issues in future ACAPs.

IV. Conclusions

This first ACAP has been a complex and contentious proceeding. The controversy is due, in part, to the fact that PG&E is now at greater risk for revenue recovery, making the forecasting stakes higher. PG&E's application in this proceeding paints a bleak picture of the future. It forecasts significant and in some cases dramatic increases for all classes of customers.

In addition, forecasting by its nature can be extremely complex. In this case, PG&E used two complicated models which were made more complex by their interaction. This decision seeks to minimize model complexities and simplify specifications and assumptions that do not detract from the model's usefulness.

The complexity and controversy were increased when PG&E made significant changes to its application during the hearing process. The introduction of these changes required additional efforts by the parties to review the data, and additional hearing days.

A major objective of this decision is to establish a framework for analyzing throughput in future ACAPs. It cannot resolve all forecasting problems. We believe forecasts will improve as the utilities, the parties, and the Commission gain experience with the ACAP process and with the evolving gas markets. While we anticipate improvements to forecasts, we intend that the guidance provided by this order be applied in the future.

We also comment on other aspects of future ACAPs. It is our intent, as time goes on, to modify our program to provide the utilities with more opportunities to compete, and thereby further encourage efficiency in gas markets. Accordingly, we do not anticipate increasing regulatory protections for PG&E, as it has requested in this proceeding, but rather reducing them, barring changes which make gas markets less competitive. Accordingly, we expect to review the viability of balancing accounts and other protective mechanisms which may be better transitional practices than permanent ones. We also intend to look further at our cost allocation practices which affect the competitiveness of the market and of the utilities, consistent with the requirements of SB 987.

Throughout, we retain our commitment to protecting the core from unnecessary rate increases and service problems. In effect, we continue to recognize that core customers are best protected in competitive markets when rates are set closer to cost, thereby preventing uneconomic bypass of utility networks. We also believe that competition, if successful, will work to reduce the cost of gas for all customers.

Findings of Fact

1. Gas throughput is the total demand for natural gas from the utility system, including sales and transport gas.

2. PG&E's estimate of gas throughput included the use of econometric models to forecast the effects of economic activity, fuel prices, weather and other factors on demand.

3. PG&E used a discount adjustment model to forecast discounts from tariffed transport rates required to keep large customers from P2B, G-IND, and COGEN on its system.

4. DRA's assumption that a recession will not occur in 1989 is supported by industry analysts.

5. Some of PG&E's customers purchase propane at retail rates.

6. Forecasted propane prices during the test period should include weighted values for the cost of retail and wholesale propane prices according to the percentage of customers who purchase propane at retail and wholesale rates.

7. Fuel oil prices declined during the final months of 1988, prior to OPEC price-setting meetings, but have since increased.

8. PG&E's estimates of customer growth during the test period are reasonable.

9. Models used to forecast required unadjusted throughput and discounts for PG&E's noncore customers should include an estimate of the effects of demand charges on customer decisions to fuel switch.

10. PG&E did not provide evidence that customer perceptions regarding service reliability have changed since D.87-12-039 was issued.

11. GC-2 customers with contracts that expire in 1989 are not distinguished from other customers in terms of the value of gas relative to the value of alternative fuels, once those contracts expire.

12. Significant numbers of PG&E's large noncore customers may elect core status. A model designed to estimate required discounts for noncore customers would provide a more accurate estimate of noncore revenue if it included core and noncore gas prices, weighted according to volumes purchased.

13. Cogeneration purchases used to generate steam are appropriately included in industrial throughput estimates.

14. Cogeneration purchases sold under the G-IND tariff are appropriately included in industrial throughput estimates.

15. PG&E appropriately estimates UEG volumes based on average hydro year conditions.

16. Estimates of UEG volumes should be based on estimates and methodologies adopted in PG&E's and SCE's ECAC proceedings, to the extent those estimates are based on average hydro year conditions.

17. PG&E's and DRA's estimates of residential and commercial throughput for the test period are almost identical.

18. TURN's proposed methodology for estimating required noncore volume discounts is more accessible and understandable than PG&E's.

19. TURN's proposed model is a reasonable alternative to PG&E's discount adjustment model for purposes of forecasting required discounts to noncore customers.

20. Workshops are likely to help interested parties understand ACAP forecasting models and will provide a forum for determining improvements to forecasting methods.

21. Changes in oil prices influence, to some extent, gas prices. Estimates of gas prices during the test period which reflect this relationship are likely to be more accurate than those which do not.

22. The noncore portfolio contains short-term supplies with prices that are firm for up to thirty days.

23. The core portfolio contains all long-term supplies and any short-term supplies needed to meet demand.

24. El Paso supplies are likely to be too expensive to be purchased economically during the test period.

25. PG&E has stipulated, in PGT's general rate case, to an estimate of 1,009 MMcf/day over the PGT pipeline. PG&E transported, on average, 1,009 MMcf/day over the PGT pipeline between January 1988 and November 1988.

26. A deferred debit account will reduce PG&E's risk of recovering costs related to pending El Paso filings at the FERC.

27. Allocating NRSA balances entirely to noncore rates is fair since core fixed costs are allocated entirely to the core, and because such allocation does not result in changes to established allocation principles.

28. Allocating CSA undercollections to the UEG class promotes efficiency and equity.

29. PG&E may realize a revenue shortfall from cogenerators during dry years when the UEG rate falls below the otherwise applicable rate to cogenerators.

30. The risk PG&E bears for a cogeneration shortfall under existing CSA accounting practices is offset by potential gains from UEG customers during a dry year, and by potential gains under the CSA during a wet year.

31. Changing CSA accounting practices at this time would provide unwarranted regulatory protections to PG&E.

32. PG&E's UEG facility switches from gas to oil whenever oil is cheaper than the incremental cost of gas. As UEG throughput falls, cogeneration gas rates increase because the fixed UEG demand charge is spread over smaller volumes in the rate parity formula.

33. PG&E's "one-company policy" is designed to promote efficient use of resources.

34. Cogenerators may opt to use the otherwise applicable gas rate when UEG rates increase.

35. This proceeding did not anticipate addressing whether SCE's Cool Water plant should be treated as a UEG facility.

36. PG&E may be able to retain additional load by discounting transition cost and implementation balancing account amounts.

37. Booking negotiated transportation revenues in excess of variable and customer related costs to TC/IBA accounts will provide appropriate safeguards in cases where PG&E discounts TC/IBA surcharges.

38. Collecting take-or-pay transition costs volumetrically will provide the utilities improved incentives to negotiate the best rates with pipelines.

39. Deferring rate implementation will place upward pressure on rates in subsequent periods.

40. Escalating EOR and GC-2 revenues according to contracted amounts provides a more accurate forecast of those revenues.

41. Updating contested information following hearings fails to permit appropriate review of such information.

Conclusions of Law

1. PG&E should be ordered to make tariff changes in accordance with the rates shown in Appendix C.

2. CACD should schedule workshops, following PG&E's next ACAP filing, to consider ACAP forecasting models and explore refinements to them.

3. The Commission should continue to use a $.02 gas premium. The premium should apply to all noncore customers, including GC-2 customers.

4. Estimates of customer discounts should reflect customers' ability to elect core status, and should weight core and noncore gas prices according to volumes purchased.

5. PG&E's request to change CSA accounting practices should not be adopted.

6. DGS' request to change the way cogeneration rates are calculated during UEG oil burn periods should not be adopted.

7. Using the Lundberg survey, a reasonable estimate of propane prices for 1989 is $0.361 per therm.

8. A reasonable estimate of No. 6 fuel oil prices in 1989 is $17 per barrel, equivalent to a $.285 delivered price and $.254 burnertip price.

9. A reasonable estimate of No. 2 fuel oil for 1989 is the equivalent of $.324 per therm.

10. Models used to estimate PG&E's unadjusted noncore throughput volume and rate discounts should include a proxy of demand charges in the amounts of $.03 per therm for volumes associated with negotiated contracts and $.05 per therm for volumes associated with default agreements.

11. A reasonable estimate of EOR throughput for the test period is 373 MMth.

12. A reasonable estimate of interutility throughput for the test period is 673 MMth.

13. A reasonable estimate of California gas prices during the test period is $1.85 per MMBtu.

14. A reasonable estimate of Rocky Mountain gas prices for the test period is $1.67 per MMBtu.

15. The currently effective price for Canadian gas supplies is $1.94 per MMBtu at the California border and is a reasonable price estimate for the test period.

16. A reasonable estimate of Southwest gas prices for the test period is $2.10 per MMBtu.

17. An estimate of 1,009 MMcf/day over the PGT line during the test period is reasonable.

18. A reasonable estimate of the core WACOG during the test period is $1.944 per MMBtu.

19. A reasonable estimate of the noncore WACOG during the test period is $2.20 per MMBtu.

20. It is reasonable to estimate storage-related transition costs based on an annual forecast.

21. It is reasonable to allocate PGA balances on an equal-cents-per-therm basis to core and core elect customers.

22. It is reasonable to allocate existing transition costs on an equal-cents-per-therm basis, with storage-related transition costs allocated using a cold year forecast.

23. It is reasonable to allocate EOR revenue credits on DRA's methodology of an equal percentage of fixed costs.

24. The existing accounting treatment of revenues from reassignment of core customers is reasonable.

25. It is reasonable to retain the $.40 per therm differential between baseline and Tier II rates.

26. A 35% differential between summer and winter commercial rates is reasonable.

27. It is reasonable to use most recent information regarding balancing account undercollections and overcollections in determining revenue requirement in this proceeding.

28. It is reasonable to adjust the Conservation Financing Account by $3.6 million to more accurately reflect the status of doubtful accounts.

29. It is reasonable to update base revenues to reflect the 1989 attrition year revenue requirement, adopted in Resolution G-2838.

30. A reasonable forecast of EOR credits is $6.9 million, adjusted for escalation using an escalation factor of 3.4% to produce an EOR revenue credit of $7.293 million.

31. A reasonable escalation factor for GC-2 revenues is 3.738%.

O R D E R

IT IS ORDERED that:

1. Within five (5) days of the effective date of this decision, Pacific Gas and Electric Company (PG&E) shall file, in accordance with General Order 96-A, tariff changes which implement the rate changes adopted in this proceeding, and which are shown in Appendix C to this decision, using the revenue requirement presented in Appendix B, Table 6. Tariff changes will be effective June 1, 1989.

2. The Executive Director shall direct the Commission Advisory and Compliance Division to schedule workshops after PG&E files its application and before hearings are held in PG&E's next ACAP proceeding. The purpose of the workshops will be to help interested parties to understand the models proposed by the utility for use in the proceeding.

This order is effective today.

Dated May 26, 1989, at San Francisco, California.

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

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

Victor Weisser, Executive Director

PACIFIC GAS AND ELECTRIC COMPANY
1989 ANNUAL COST ADJUSTMENT PROCEEDING

APPENDICES

APPENDIX A
Page 1

List of Appearances

Applicant: Harry W. Long, Jr., for Pacific Gas and Electric Company.

Interested Parties: Messrs. Lindsay, Hart, Neil & Weigler, by Michael P. Alcantar, Attorney at Law, for Cogenerators of Southern California; C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Richard O. Baish, Michael D. Ferguson, Randolph L. Wu, and Phyllis Huckabee, for El Paso Natural Gas Company; W. Randolph Baldschun, Anthony C. Bennetti, Ronald G. Oechsler, and Patrick J. Power, Attorney at Law, for City of Palo Alto; Barkovich & Yap, by Barbara R. Barkovich, for California Large Energy Consumers Association; Messrs. Morrison & Foerster, by Jerry R. Bloom, Attorney at Law (New York), for California Cogeneration Council; Matthew Brady and Dian Grueneich, Attorneys at Law, for Department of General Services; Karen Edson, for KKE & Associates; Michel Peter Florio, Attorney at Law, for Toward Utility Rate Normalization; Richard K. Durant, Frank J. Cooley, Attorneys at Law, and Michael Gonzales, for Southern California Edison Company; Steven M. Harris, for Enron/Transwestern Pipeline; Rand L. Havens, for Mission Resources; Messrs. Brady & Berliner, by John Jimison, Attorney at Law, for Canadian Producer Group; Messrs. Luce, Forward, Hamilton & Scripps, by John W. Leslie and Steven S. Wall, Attorneys at Law, for Salmon Resources, Ltd., and Mock Resources, Inc.; Henry F. Lippitt, 2nd, Attorney at Law, for California Gas Producers Association; Thomas D. Clarke, Glen J. Sullivan, Lisa T. Horwitz, Attorneys at Law, and L. P. Lorenz, for Southern California Gas Company; Messrs. Graham and James, by Vickie Thompson and Martin Mattes, Attorneys at Law, for Kern River Gas Transmission Company and California Hotel & Motel Association; Messrs. Squire, Sanders & Dempsey, by Keith R. McCrea and Michael T. Mishkin, Attorney at Law, for California Industrial Group; Barton M. Myerson, Attorney at Law, and Judy Obst, for San Diego Gas & Electric Company; Jeff Nahigian, for IEP; Thomas J. O'Rourke and Thomas R. Sheets, Attorney at Law (Nevada), for Southwest Gas Corporation; Paul Remo, for Chevron, U.S.A.; John Quinley, for Cogeneration Service Bureau; Messrs. Skaff & Anderson, by Andrew J. Skaff, Attorney at Law, for Natural Gas Clearinghouse; Antonio Radillo and A. Kirk McKenzie, Attorneys at Law, for California Energy Commission; Andrew Safir, for Recon Research Corporation; Donald W. Schoenbeck, for R.C.S., Inc; Messrs. Armour, St. John, Wilcox, Goodin & Schlotz, by James D. Squeri, Attorney at Law, for California Building Industry Association; Brian Sway, for California Gas Cooperative

APPENDIX A
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List of Appearances

Formation Committee; Barakat, Howard & Chamberlin, by Nancy Thompson, for Barakat, Howard & Chamberlin; Eric Toolson and Rudy Iwasko, for Sacramento Municipal Utility District; Kevin Woodruff, for Henwood Energy Services, Inc.; Harry K. Winters, for University of California; Ward A. Mefford, for Modesto Irrigation District; and Jones, Day, Reavis & Pogue, by Norman A. Pedersen, Attorney at Law, for Southern California Power Pool and Imperial Irrigation District.

Division of Ratepayer Advocates: Patrick Gileau and Izetta Jackson, Attorneys at Law.

(END OF APPENDIX A)

APPENDIX B

TABLE 1A

PACIFIC GAS AND ELECTRIC COMPANY

ANNUAL COST ALLOCATION PROCEEDING

ADOPTED DISCOUNT ADJUSTMENT MODEL FOR G-IND

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	#2 OIL	#6 OIL	PROPANE	
Alternate Fuel Price (cents/therm)	37.4	28.5	36.1	
Gas Premium (cents/therm)	2.0	2.0	2.0	
Exit Demand Charges (cents/therm)	4.4	4.4	4.4	1/
Less: Average Cost of Gas (cents/therm)	21.4	21.4	21.4	2/
Maximum Transportation Rate (cents/therm)	22.4	13.5	21.1	3/
Seed Default Rate (cents/therm)	14.9	14.9	14.9	
Percent Discount Required	0.0%	9.6%	0.0%	4/
Unadjusted Volume Forecast (MDth)	40,736	53,093	33,947	
Discount Adjustment Volume (MDth)	0	5,106	0	5/

FOOTNOTES:

1/ ((ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT)) * 3 CENTS) + ((1 - (ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT))) * 5 CENTS)

2/ (55% * CORE PORTFOLIO PRICE) + (45% * NONCORE PORTFOLIO PRICE)

3/ ALTERNATE FUEL PRICE + GAS PREMIUM + EXIT DEMAND CHARGES - AVERAGE COST OF GAS

4/ (SEED DEFAULT RATE - MAXIMUM TRANSPORTATION RATE) / SEED DEFAULT RATE

5/ PERCENT DISCOUNT REQUIRED * UNADJUSTED VOLUME FORECAST

APPENDIX B

TABLE 1B
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED DISCOUNT ADJUSTMENT MODEL FOR P2B

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	#2 OIL	#6 OIL	PROPANE	
Alternate Fuel Price (cents/therm)	37.4	28.5	36.1	
Gas Premium (cents/therm)	2.0	2.0	2.0	
Exit Demand Charges (cents/therm)	4.4	4.4	4.4	1/
Less: Average Cost of Gas (cents/therm)	21.4	21.4	21.4	2/
Maximum Transportation Rate (cents/therm)	22.4	13.5	21.1	3/
Seed Default Rate (cents/therm)	15.8	15.8	15.8	
Percent Discount Required	0.0%	14.4%	0.0%	4/
Unadjusted Volume Forecast (MDth)	465	1,861	5,582	
Discount Adjustment Volume (MDth)	0	269	0	5/

FOOTNOTES:

1/ ((ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT)) * 3 CENTS) + ((1 - (ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT))) * 5 CENTS)

2/ (55% * CORE PORTFOLIO PRICE) + (45% * NONCORE PORTFOLIO PRICE)

3/ ALTERNATE FUEL PRICE + GAS PREMIUM + EXIT DEMAND CHARGES - AVERAGE COST OF GAS

4/ (SEED DEFAULT RATE - MAXIMUM TRANSPORTATION RATE) / SEED DEFAULT RATE

5/ PERCENT DISCOUNT REQUIRED * UNADJUSTED VOLUME FORECAST

APPENDIX B

TABLE 1C
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED DISCOUNT ADJUSTMENT MODEL FOR COGEN

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	#2 OIL	#6 OIL	PROPANE	
Alternate Fuel Price (cents/therm)	37.4	28.5	36.1	
Gas Premium (cents/therm)	2.0	2.0	2.0	
Exit Demand Charges (cents/therm)	4.4	4.4	4.4	1/
Less: Average Cost of Gas (cents/therm)	21.4	21.4	21.4	2/
Maximum Transportation Rate (cents/therm)	22.4	13.5	21.1	3/
Seed Default Rate (cents/therm)	13.9	13.9	13.9	
Percent Discount Required	0.0%	2.8%	0.0%	4/
Unadjusted Volume Forecast (MDth)	29,934	2,661	380	
Discount Adjustment Volume (MDth)	0	75	0	5/

FOOTNOTES:

1/ ((ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT)) * 3 CENTS) + ((1 - (ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT))) * 5 CENTS)

2/ (55% * CORE PORTFOLIO PRICE) + (45% * NONCORE PORTFOLIO PRICE)

3/ ALTERNATE FUEL PRICE + GAS PREMIUM + EXIT DEMAND CHARGES - AVERAGE COST OF GAS

4/ (SEED DEFAULT RATE - MAXIMUM TRANSPORTATION RATE) / SEED DEFAULT RATE

5/ PERCENT DISCOUNT REQUIRED * UNADJUSTED VOLUME FORECAST

APPENDIX B

TABLE 2A
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CUSTOMER CLASS	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)
CORE THROUGHPUT		
Residential IM	180,483	180,483
Residential MM	32,447	32,447
Total Residential	212,930	212,930
Small Commercial	68,353	68,353
Large Commercial Core	14,914	14,914
Large Commercial Noncore	0	0
Large Commercial Transport-Only	0	0
Total Commercial	83,267	83,267
Interdepartmental C&C	80	80
Interdepartmental OPS	97	97
PG&E Start-Up Fuel	1,474	1,474
SoCal Edison	0	0
Total Other	1,651	1,651
TOTAL CORE	297,848	297,848
NONCORE THROUGHPUT		
Large P2B Core Elect	4,349	4,201
Large P2B Noncore	1,239	1,197
Large P2B Transport-Only	2,320	2,241
Total Large P2B	7,908	7,639
Industrial Core Elect	70,277	67,469
Industrial Noncore	20,207	19,399
Industrial Transport-Only	37,292	35,802
Total Industrial	127,776	122,670
Cogeneration Core Elect	18,135	18,094
Cogeneration Noncore	5,075	5,063
Cogeneration Transport-Only	9,765	9,743
Total Cogeneration	32,975	32,900
EOR Core Elect	0	0
EOR Noncore	3,721	3,721
EOR Transport-Only	14,881	14,881
Total EOR	18,602	18,602

APPENDIX B

TABLE 2A
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CUSTOMER CLASS	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)
EOR Cogeneration Core Elect	0	0
EOR Cogeneration Noncore	931	931
EOR Cogeneration Transport-Only	17,727	17,727
Total EOR Cogeneration	18,658	18,658
Wholesale Core Elect	6,256	6,256
Wholesale Noncore	0	0
Wholesale Transport-Only	4,170	4,170
Total Wholesale	10,426	10,426
UEG-PG&E Core Elect	138,709	138,709
UEG-PG&E Noncore	0	0
UEG-PG&E Transport-Only	0	0
Total UEG-PG&E	138,709	138,709
UEG-SCE Core Elect	3,823	3,823
UEG-SCE Noncore	0	0
UEG-SCE Transport-Only	0	0
Total UEG-SCE	3,823	3,823
GC2-Industrial Core Elect	14,398	14,398
GC2-Industrial Noncore	3,802	3,802
GC2-Industrial Transport-Only	7,977	7,977
Total GC2-Industrial	26,177	26,177
GC2-Cogeneration Core Elect	7,163	7,163
GC2-Cogeneration Noncore	1,974	1,974
GC2-Cogeneration Transport-Only	3,889	3,889
Total GC2-Cogeneration	13,026	13,026
Steam Heat	1,033	1,033
Interdepartmental	86	86
TOTAL NONCORE	399,199	393,749
OTHER THROUGHPUT		
Gas Department Use Core	5,758	5,758
Gas Department Use Noncore	303	303

APPENDIX B

TABLE 2A
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CUSTOMER CLASS	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)
Lost and Unaccounted For Core	16,769	16,769
Lost and Unaccounted For Noncore	875	875
Interutility Noncore	47,079	47,079
Interutility Transport-only	20,192	20,192
TOTAL OTHER	90,976	90,976
TOTAL THROUGHPUT	788,023	782,573

TABLE 2B
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

TYPE OF SERVICE	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)
Core Gas Requirements	297,848	297,848
Core-Elect Gas Requirements	264,229	261,232
Noncore Gas Requirements	84,028	83,167
Total Requirements	646,105	642,246
Total Transport-Only	118,213	116,622
Total Other	23,705	23,705
TOTAL THROUGHPUT	788,023	782,573

APPENDIX B

TABLE 3
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED COST OF GAS

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	VOLUME (MDth)	PRICE ($/Dth)	COST ($000)
CORE:			
Supply Sources:			
California	122,815	1.850	227,208
Rocky Mountain	2,705	1.670	4,517
PGT-Canadian	368,285	1.940	714,473
El Paso	---	2.844	---
Southwest	88,660	2.100	186,186
Subtotal	582,465	1.944	1,132,384
Withdrawal from Storage	39,329	2.050	80,629
Injection to Storage	(37,190)	1.944	(72,302)
Subtotal (including storage-related transition costs)	584,604	1.951	1,140,711
Less: storage-related transition costs			4,169
TOTALS	584,604		1,136,542
CORE Weighted Average Cost of Gas (WACOG)		1.944	
NONCORE:			
Noncore Demand	84,028		
Noncore Gas Department Use (GDU)	303		
Noncore Lost and Unaccounted For (LUAF)	875		
TOTALS	85,206		187,453
NONCORE Weighted Average Cost of Gas (WACOG)		2.200	
TOTAL COST OF GAS			1,323,996

APPENDIX B

TABLE 4
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED STORAGE-RELATED TRANSITION COSTS

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

Weighted Average Price of Withdrawals ($/Dth)	2.050
Less: Weighted average price of core gas ($/Dth)	1.944
Subtotal ($/Dth)	0.106
Volume of Withdrawals (MDth)	39,329
Storage-Related Transition Costs ($000)	4,169

APPENDIX B

TABLE 5
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED PORTFOLIO PRICES

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CORE:	
CORE Cost of Gas ($000) 1/	$1,092,747
Add: Purchase Gas Account ($000)	60,843
Add: Franchise Fees and Uncollectibles @ 0.00943% ($000)	10,878
TOTAL CORE COST ($000)	$1,164,469
CORE VOLUME (MDth)	562,077
CORE PORTFOLIO PRICE ($/Dth)	$2.072
NONCORE:	
NONCORE Cost of Gas ($000) 2/	$184,862
Add: Franchise Fees and Uncollectibles @ 0.00943% ($000)	1,743
TOTAL NONCORE COST ($000)	$186,605
NONCORE VOLUME (MDth)	84,028
NONCORE PORTFOLIO PRICE ($/Dth)	$2.221

FOOTNOTES:

1/ Excludes GDU and LUAF expenses of $43,795,274.

2/ Excludes GDU and LUAF expenses of $2,591,600.

APPENDIX B

TABLE 6
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED REVENUE REQUIREMENT SUMMARY

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989
(In Thousands of Dollars)

PROCUREMENT REVENUE REQUIREMENT		
1989 Gas Procurement Costs:		
Core/Core-Elect	$1,092,747	
Noncore	184,862	
Total 1989 Commodity Costs		1,277,609
Core Purchased Gas Account Balance (CPGA)		60,843
Franchise Fees and Uncollectibles		12,599
Total Procurement Revenue Requirement		$1,351,051
TRANSMISSION REVENUE REQUIREMENT		
1989 Forecast Costs:		
Base Revenue Fixed Costs (includes EOR and Interutility Credits)		$1,017,089
Pipeline Demand Charges		174,844
Gas Storage Carrying Costs		14,691
Transition Costs		31,570
CFA Debt Service/Expense		8,342
GEDA		50,000
LUAF and CDU Gas		46,387
CPUC Fee		3,831
1989 Total Forecast Costs		$1,346,753
Balancing Account Amortization: 1/		
Core Gas Fixed Cost Balancing Account (CFCA)		$3,189
Core Implementation Balancing Account (CIBA)		50,819
Noncore Implementation Balancing Account (NIBA)		82,605
Noncore Transition Cost Account (NTCA)		2,446
Negotiated Revenue Stability Account (NRSA)		16,003
Enhanced Oil Recovery Account (EORA)		(211)
Interutility Balancing Account		(1,922)
CFA Debt Service/Expense		(8,526)
Total Forecast Account Balances		$144,403
Add: Franchise Fees & Uncollectibles		4,460
Total Transmission Revenue Requirement		$1,495,616
TOTAL REVENUE REQUIREMENT		$2,846,667

1/ Balancing account balances are current through January 31, 1989.

APPENDIX B

TABLE 7
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED BASE REVENUE FIXED COSTS

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989
(in Thousands of Dollars)

BASE FIXED COSTS:	
Common Distribution	$259,991
Transmission	179,757
Storage	45,031
Customer Related	460,638
Production Related	7,399
50% Administrative and General	74,273
Franchise Fees and Uncollectibles	9,738
TOTAL BASE FIXED COSTS	$1,036,827
Less: Other Operating Expenses	(5,045)
SUBTOTAL BASE REVENUE FIXED COSTS	$1,031,782
Less: EOR and Interutility Credits	(14,693)
TOTAL BASE REVENUE FIXED COSTS	$1,017,089

All information pertaining to Base Revenue Fixed Costs is based on adopted allocations from the workpapers for PG&E Attrition Resolution, G-2838 dated December 19, 1988.

TABLE 8
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED TRANSITION COSTS

FORECAST PERIOD, JANUARY 1, 1989 - DECEMBER 31, 1989
(in Thousands of Dollars)

El Paso Liquids Settlement	$27,347
Storage-Related Transition Costs	4,169
Opinion No. 270-Related Costs	0
Canadian Take-or-Pay	54
TOTAL TRANSITION COSTS	$31,570

(END OF APPENDIX B)

APPENDIX C

TABLE 1

PACIFIC GAS AND ELECTRIC COMPANY 1989 ACAP

REVENUE REQUIREMENT CHANGE

(In Thousands of Dollars)

PROCUREMENT REVENUE REQUIREMENT	
Total Procurement Revenue Requirement	$1,351,051
Less Procurement Revenue Requirement @ Present Rates	1,211,661
Change in Procurement Revenue Requirement	139,390
Core	74,254
Core-Elect, Core-Elect Whlse	65,136
Noncore 1/	0
Total Change	139,390
TRANSMISSION REVENUE REQUIREMENT	
Total Transmission Revenue Requirement	1,495,616
Less Transmission Revenue Requirement @ Present Rates	1,483,589
Change in Transmission Revenue Requirement	12,027
Core	13,026
Noncore	(998)
Total Change	12,027
TOTAL REVENUE REQUIREMENT	2,846,667
TOTAL CHANGE IN REVENUE REQUIREMENT	151,417

1/ Adopted noncore procurement revenue requirement is assumed to be the same as revenue at present rates.

APPENDIX C - Table 2
PG&E ANNUAL COST ADJUSTMENT PROCEEDING - ADOPTED COST ALLOCATION
FORECAST PERIOD, JAN 1, 1989 - DEC 1989

[illegible]

APPENDIX C

TABLE 3

PG&E ANNUAL COST ALLOCATION PROCEEDING

DETAIL UNDERLYING ADOPTED COST ALLOCATION:
BASIS FOR ADJUSTING CUSTOMER AND DEMAND CHARGE REVENUES
TO RECOVER RETURN AND TAXES FROM VOLUMETRIC CHARGES 1/

	SYSTEM PERCENT	SYSTEM DEPRECIATED RATEBASE ($000'S)	RTN BASED ON WT COST OF ROE & PRFD OF 6.70%	TAXES STATE ($000'S)	TAXES FEDERAL ($000'S)	TOTAL ($000'S)
				33,496	112905	
TOTAL DEPR RB		1,972,151	132,134			
PRODUCTION	0.00075	1,473	99	25	85	208
STORAGE	0.07657	151,017.	10,118	2,565	8,646	21,329
DISTRIBUTION	0.27275	537,905	36,040	9,136	30,795	75,971
CUSTOMER	0.38597	761,182	50,999	12,928	43,578	107,505
TRANSMISSION	0.26396	520,573	34,878	8,842	29,803	73,523
	1.00000	1972150	132,134	33,495	112,905	278,536
						278536.117

1/ Depreciated rate base and state and federal taxes reflect PG&E base cost revenues updated to reflect its 1989 Attrition Resolution, G-2838 (12/19/88). Return (i.e., weighted cost of preferred and common equity) reflects financial attrition authorized in D. 88-12-094 (12/19/88).

APPENDIX C-4

ADOPTED CORE RATES AND REVENUES

CLASS OF SERVICE	ADJUSTED CUST/SALES FORECAST (MTH/CUST)	PRESENT RATES ($/TH &/MO)	PRESENT REVENUES (M$)	ADOPTED RATES ($/TH &/MO)	ADOPTED REVENUES (M$)	ADOPTED RATE CHANGE (%)
	(a)	(b)	(c)	(d)	(e)	(f)
RESIDENTIAL						
	2/		2/			
Tier I (Baseline)	1,485,956	0.41122	611,055	0.44181	656,504	7.4%
Tier II	638,836	0.81116	518,198	0.84204	537,923	3.8%
GS,GT Adj.			(6,860)		(6,860)	0.0%
TOTAL RESIDENTIAL	2,124,792	0.52824	1,122,393	0.55891	1,187,567	5.8%
SMALL COMMERCIAL						
SCHEDULE G-NR1 1/						
Cust Charg($/MO)	2,359,668	12.12	28,599	11.88	28,030	-2.0%
Summer Rate	334,820	0.43233	144,747	0.45732	153,121	5.8%
Winter Rate	363,450	0.58364	212,119	0.61739	224,392	5.8%
Total G-NR1	698,270	0.55203	385,465	0.58078	405,543	5.2%
LARGE COMMERCIAL						
SCHEDULE G-NR2						
Cust Charg($/MO)	2884	138.52	399	135.85	388	-2.9%
Summer Rate	72,130	0.37350	26,941	0.38482	27,757	3.0%
Winter Rate	78,780	0.50423	39,723	0.51951	40,927	3.0%
Total G-NR2	150,910	0.44439	67,063	0.4577	69,072	3.0%
0.55891						
COMMERCIAL (TRANSPORT ONLY)						
SCHEDULE G-NR3						
Cust Charg($/MO)		138.52	0	135.85	0	-1.9%
Summer Rate	0	0.19098	0	0.17765	0	-7.0%
Winter Rate	0	0.32171	0	0.31234	0	-2.9%
Total Commercial	849,180	0.5329	452,528	0.55891	474,615	4.9%
TOTAL CORE	2,973,972	0.52957	1,574,921	0.55891	1,662,196	5.5%

1/ CPUC surcharge of $.00076/therm reflected in rates, except for PG&E and SCE-UEG volumes.

2/ TI and TII sales realigned reducing baseline quantities & rates (AL 1539-G).

APPENDIX C-5

ADOPTED NONCORE TRANSPORT RATE AND REVENUES

NONCORE CUSTOMER CLASS	ADJUSTED FORECAST DELIVERIES (MTH)	HISTORICAL BILLING DETERMINANTS (MTH/CUST)	PRESENT RATES $/TH OR $/MO	PRESENT REVENUES (M$)	ADOPTED RATE $/TH OR $/MO	ADOPTED REVENUES TOTAL NON-GAS (M$)	ADOPTED RATE CHANGE (%)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
PRIORITY P2B							
Customer Charge		74	156.77 3/	140	207.98	186	32.7%
Demand Charge D1		77,833	0.08844	6,884	0.08503	6,618	-3.9%
Demand Charge D2:							
Summer		105,758	0.01513	1,600	0.01033	1,092	-31.7%
Winter		46,638	0.03436	1,602	0.01778	829	-48.3%
Volumetric Charg	76,390		0.04353	3,325	0.04346	3,320	-0.2%
TOT/AVE P2B	76,390		0.17740	13,551	0.15769	12,046	-11.1%
INDUSTRIAL G-IND 1/							
Customer Charge		827	555.88 3/	5,516	519.71	5,157	-6.5%
Demand Charge D1		1,287,932	0.05963	76,799	0.08597	110,719	44.2%
Demand Charge D2:							
Summer		1,510,157	0.00671	10,133	0.00718	10,842	7.0%
Winter		884,689	0.02238	19,799	0.01327	11,738	-40.7%
Volumetric Charg	1,276,120		0.04325	55,155 4/	0.04076	52,017	-5.8%
INDUST Net of GC-2	1,276,120		0.13118	167,403	0.14926	190,473	13.8%
GC-2 Industrial	261,770			13,530		14,036	3.7%
	----------		----------	----------	----------	----------	----------
TOTAL INDUSTRIAL	1,537,890		0.11765	180,933	0.13298	204,508	13.0%
UTILITY ELEC GEN 2/							
Customer Charge		1	74,727	897	99,615	1,195	33.3%
Demand Charge			3/	166,082		146,579	-11.7%
Volumetric Charg:							
Tier I	256,612		0.04469	11,468	0.04480	11,496	0.2%
Tier II	1,130,478		0.01439	16,268	0.01388	15,687	-3.6%
TOT/AVE UEG	1,387,090		0.14038	194,714	0.12613	174,957	-10.1%
COGENERATION							
Cogen NetofGC-2	329,000		0.13828	45,494	0.12613	41,498	-8.8%
GC-2 Cogen	130,260			6,770		7,024	3.8%
TOT/AVE COGEN	459,260		0.11380	52,264	0.10565	48,522	-7.2%
NONCORE SUBTOTAL							
Net of GC-2	3,068,600		0.13725	421,162	0.13654	418,973	-0.5%
Including GC-2	3,460,630		0.12757	441,462	0.12715	440,033	-0.3%
WHOLESALE							
Demand Charges			3/	8,931		9,188	2.9%
Volumetric Charg	104,260		0.01040	1,084	0.01207	1,258	16.1%
TOT/AVE WHOLESALE	104,260		0.09606	10,015	0.10019	10,446	4.3%
TOT NONCORE							
Net of GC-2	3,172,860		0.13590	431,177	0.13534	429,419	-0.4%
Including GC-2	3,564,890		0.12665	451,477	0.12637	450,479	-0.2%

1/ Estimated billing determinants include UEG-SCE, steam heat, interdepartmental volumes.

2/ Revenue not based on existing tariff tiering.

3/ Customer charges for these schedules are tiered; demand charges for wholesale & UEG vary monthly.

4/ Revenues reflect exclusion of 49.4 MMTH from CPUC surcharge of $ .00076/therm.

(END OF APPENDIX C)

APPENDIX D

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
COMPARISON SUMMARY

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	ADOPTED	CIG	DRA	PG&E
CORE Weighted Average Cost of Gas (WACOG) ($/Dth)	1.944	1.684 /1	1.871 /2	1.920 /3
NONCORE Weighted Average Cost of Gas (WACOG) ($/Dth)	2.200	1.880 /1	1.969 /2	2.200 /3
Gas Prices by Supply Source:				
California	1.850	1.558 /1	1.700 /4	1.850 /3
Rocky Mountain	1.670	1.350 /1	1.670 /4	1.670 /3
PGT- Canadian	1.940	1.611 /1	1.847 /4	1.847 /3
El Paso	2.844	-- /1	2.844 /4	2.844 /3
Southwest	2.100	2.014 /1	2.030 /4	2.200 /3
Adjusted Industrial Throughput (MDth)	163,209 /5	140,700 /6	159,877 /7	140,785 /7
Revenue Requirement ($000)	2,846,667	--	2,736,853 /8	2,656,656 /8

/1 Exhibit 56, Table 2.

/2 Exhibit 51, Table 4-1.

/3 Exhibit 20, page MAS-4.

/4 DRA Opening Brief, pages 26 and 27.

/5 Includes throughput estimates for P2B, G-IND, and COGEN customer classes.

/6 Exhibit 57, page 8.

/7 Exhibit 50, Table 3-1.

/8 Exhibit 52, Table 6-1.

(END OF APPENDIX D)

State of California

Public Utilities Commission
San Francisco

MEMORANDUM

H-3a

Date : May 24, 1989

To : The Commission
(Meeting of May 26, 1989)

From : President Wilk *mw*

File No.:

Subject : Alternate Pages to H-3 (PG&E ACAP)

I support the ALJ's proposed decision in this case with two exceptions:

1. Non-core WACOG. The ALJ proposes $1.90, which I believe is unrealistically low to expect for the ACAP period. Prices in the recent few months have been significantly higher than $1.90, even during relatively low-cost shoulder months. I propose to substitute PG&E's forecast of $2.20, which is close to current prices.

2. Exit costs. We are all now about as well acquainted with exit costs as we are with our immediate families. I support ALJ Malcolm's adoption of exit costs in the oil prices used in the discount adjustment model, both because I believe PG&E failed convincingly to argue against them and because exit costs appear to be included in the gas prices used in the forecast.

I do propose to substitute a somewhat fuller discussion of exit costs than is contained in the proposed decision, including a call for testimony in the next ACAP. Judge Malcolm agrees with the new language.

To keep the flood of paper to a minimum, I have attached to this alternate the revenue and rate tables resulting from my proposed change to the non-core WACOG.

We agree with the parties who argue that PG&E has not demonstrated why it can transport less than the maximum capacity over the PGT line during the test period. PG&E's witness testified that average deliveries on the PGT line were 1,009 MMcf/day during January through November 1988. PG&E forecasts no transport of Canadian gas over the PGT pipeline in 1989, and Canadian gas is less expensive than Southwest gas. We also note that PG&E has stipulated to forecasts of full capacity over the PGT pipeline in the PGT rate case. Accordingly, we will adopt an estimate of 1,009 MMcf/day of Canadian gas over the PGT pipeline for the test period.

3. <u>Noncore WACOG</u>

As we determined in D.87-12-039, the noncore portfolio contains only short-term supplies with prices that are firm for up to 30 days. PG&E estimated a noncore WACOG of $2.20 per MMBtu for 1989, mainly on the basis of estimates of Southwest gas spot prices.

DRA forecasts a noncore WACOG of $1.97 based upon a 12-month historical average of spot prices at the California border provided in the reports of Natural Gas Week. DRA states PG&E's estimate relies too heavily on recent winter prices, which tend to be higher than average annual prices. As discussed above, DRA states the effects of the El Paso rate case on Southwest supplies cannot be inferred from PG&E's data. TURN supports DRA's position.

CIG estimated the noncore WACOG to be $1.82 for reasons presented in the previous section on the effects of oil price changes on gas prices.

We will adopt a noncore WACOG of $2.20, consistent with recent trends in the spot market.

4. <u>Transition Costs</u>

In D.87-12-039, we determined that transition costs are those which:

- Took effect before December 3, 1986;

alternative fuels. A number of parties criticized the model for this omission.

DRA, CIG, and TURN argue that customers will surely consider these "exit costs" in their fuel switching decisions. Customers do not have infinitely long time horizons, as PG&E assumes. Instead, the model should assume a shorter term planning horizon. CIG points to PG&E's testimony to argue that demand charges have the effect of increasing a customer's alternate fuel price.

Similarly, CPG and Salmon/Mock criticize the omission of demand charges as one variable which would influence switching decisions. DGS goes further to suggest that each of the major gas utilities be required to submit a methodology for incorporating demand charges in future forecasts.

CIG proposes, based on a review of PG&E's contracts, that exit costs averaged $.03 per therm in 1989. For default agreements, estimated exit costs would be about $.05 per therm. CIG proposes that these amounts be added to the cost of alternate fuels in the DA model. CIG also supports TURN's methodology as a sound alternative. TURN would apply half of the D-1 charge plus all of the fully ratcheted D-2, at 100% load factor.

In response, PG&E states that the DA model does not calculate load loss; it calculates discounts necessary to retain load. In addition, PG&E argues that including exit charges as an assumption in the DA model is inconsistent with the way rates are negotiated with customers because transport rates are based on estimates of alternate fuel prices plus a premium.

According to PG&E, incorporating demand charge effects in a one-year test period is a difficult task. PG&E's assumption that customers look at gas use as an annual decision is most reasonable. PG&E states that it would like to study the CIG and TURN proposals.

~~Demand charges present real costs to customers. Accordingly, it is reasonable to assume that customers would~~

INSERT

INSERT -- PAGE 25

Prudent decision-makers, when faced with a prospective fuel choice decision, should consider only prospective costs, not costs already incurred. Since already-incurred costs must be paid no matter what the fuel choice decision, they favor neither one choice nor the other, and so should be ignored in comparing prospective fuel costs. Since exit costs are by definition already incurred, we believe that in a world of perfect information and ideal decision-making oil prices should not be adjusted to include gas system exit costs in forecasting non-core throughput and revenues.

Our gas industry structure is still relatively new. As with several difficult questions in this ACAP, experience will eventually settle for us the proper treatment of exit costs. We will simply observe the behavior of customers operating under our new gas structure. For the present proceeding, however, we must choose between our belief that rational customers will view exit costs as sunk and the claim by TURN, CIG, and DRA (among others) that in the real world customers do consider exit costs in making fuel purchase decisions.

The balance of the record before us convinces us that the conservative approach is for us to include exit costs in our forecast for the present and invite testimony on this issue for the next ACAP.

~~include demand charges in calculating their most economic fuel options.~~

We will adopt CIG's recommendation to add $.03 per therm to the cost of alternate fuels for volumes associated with negotiated contracts and $.05 per therm to the cost of alternate fuels for volumes associated with default agreements. Weighting these amounts according to usage, the adjustment to the model is $0.044. While this method provides only a rough proxy of exit costs, it is a conservative estimate which assumes customers make choices on an annual basis. ~~It is simple and intuitively sound. PG&E should, in its next ACAP, propose a more precise method for estimating the effects of exit costs. Finally, we note that if PG&E is negotiating contracts without taking into account the effects of demand charges, as it seems to state, it may be losing revenue unnecessarily.~~

e. Gas Premium

The DA model includes a premium for gas to reflect its value to customers relative to the value of alternate fuels.

PG&E requests that the $.02 per therm premium on gas, adopted in D.87-12-039, be reduced to $.017 per therm. PG&E states that it has made this assumption because of changed customer perceptions with regard to service reliability, caused by curtailments last winter on the Southern California Gas Company (SoCal) gas system.

DRA, DGS, CIG, and TURN recommended against this change. DGS points out that the PG&E witness testified that lowering the premium creates a perception of shortage among customers, even though PG&E does not anticipate curtailments. Thus, the reduced premium is a self-fulfilling prophecy.

PG&E also proposes eliminating the premium assumed for GC-2 customers whose contracts expire in 1989. This change is reasonable, according to PG&E, because it expects some resistance

APPENDIX C
TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY 1989 ACAP
REVENUE REQUIREMENT CHANGE
(In Thousands of Dollars)

PROCUREMENT REVENUE REQUIREMENT	
Total Procurement Revenue Requirement	$1,351,051
Less Procurement Revenue Requirement @ Present Rates	1,211,661
Change in Procurement Revenue Requirement	139,390
Core	74,254
Core-Elect, Core-Elect Whlse	65,136
Noncore 1/	0
Total Change	139,390
TRANSMISSION REVENUE REQUIREMENT	
Total Transmission Revenue Requirement	1,495,616
Less Transmission Revenue Requirement @ Present Rates	1,483,589
Change in Transmission Revenue Requirement	12,027
Core	13,026
Noncore	(998)
Total Change	12,027
TOTAL REVENUE REQUIREMENT	2,846,667
TOTAL CHANGE IN REVENUE REQUIREMENT	151,417

1/ Adopted noncore procurement revenue requirement is assumed to be the same as revenue at present rates.

THE NEXT 1

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APPENDIX C - Table 2

PG&E ANNUAL COST ADJUSTMENT PROCEEDING - ADOPTED COST ALLOCATION FORECAST PERIOD, JAN 1, 1989 - DEC 1989

APPENDIX C

TABLE 3

PG&E ANNUAL COST ALLOCATION PROCEEDING

DETAIL UNDERLYING ADOPTED COST ALLOCATION:
BASIS FOR ADJUSTING CUSTOMER AND DEMAND CHARGE REVENUES
TO RECOVER RETURN AND TAXES FROM VOLUMETRIC CHARGES 1/

	SYSTEM PERCENT	SYSTEM DEPRECIATED RATEBASE (1000'S)	RTN BASED ON WT COST OF ROE & PRFD OF 6.70%	TAXES STATE ($000'S)	TAXES FEDERAL ($000'S)	TOTAL ($000'S)
				33,496	112906	
TOTAL DEPR RB		1,972,151	132,134			
PRODUCTION	0.00075	1,473	99	25	84	208
STORAGE	0.07657	151,017.	10,118	2,565	8,646	21,329
DISTRIBUTION	0.27275	537,905	36,040	9,134	30,795	75,971
CUSTOMER	0.38597	761,182	50,999	12,928	43,578	107,505
TRANSMISSION	0.26396	520,573	34,878	8,842	29,801	73,523
	1.00000	1972150	132,134	33,496	112,906	278,536
						278536.117

1/ Depreciated rate base and state and federal taxes reflect PG&E base cost revenues updated to reflect its 1989 Attrition Resolution, G-2838 (12/19/88). Return (i.e., weighted cost of preferred and common equity) reflects financial attrition authorized in D. 88-12-094 (12/19/88).

ALT-COM-GMW

APPENDIX C-4

ADOPTED CORE RATES AND REVENUES

CLASS OF SERVICE	ADJUSTED CUST/SALES FORECAST (MTH/CUST)	PRESENT RATES ($/TH &/MO)	PRESENT REVENUES (M$)	ADOPTED RATES ($/TH &/MO)	ADOPTED REVENUES (M$)	ADOPTED RATE CHANGE (%)
	(a)	(b)	(c)	(d)	(e)	(f)
RESIDENTIAL						
		2/	2/			
Tier I (Baseline)	1,485,956	0.41122	611,055	0.44181	656,504	7.4%
Tier II	638,836	0.81116	518,198	0.84204	537,923	3.8%
GS,GT Adj.			(6,860)		(6,860)	0.0%
TOTAL RESIDENTIAL	2,124,792	0.52824	1,122,393	0.55891	1,187,567	5.8%
SMALL COMMERCIAL						
SCHEDULE G-NR1 1/						
Cust Charg($/MO)	2,359,668	12.12	28,599	11.88	28,030	-2.0%
Summer Rate	334,820	0.43233	144,747	0.45732	153,121	5.8%
Winter Rate	363,450	0.58364	212,119	0.61739	224,392	5.8%
Total G-NR1	698,270	0.55203	385,465	0.58078	405,543	5.2%
LARGE COMMERCIAL						
SCHEDULE G-NR2						
Cust Charg($/MO)	2884	138.52	399	135.85	388	-2.9%
Summer Rate	72,130	0.37350	26,941	0.38482	27,757	3.0%
Winter Rate	78,780	0.50423	39,723	0.51951	40,927	3.0%
Total G-NR2	150,910	0.44439	67,063	0.4577	69,072	3.0%
0.55891						
COMMERCIAL (TRANSPORT ONLY)						
SCHEDULE G-NR3						
Cust Charg($/MO)		138.52	0	135.85	0	-1.9%
Summer Rate	0	0.19098	0	0.17765	0	-7.0%
Winter Rate	0	0.32171	0	0.31234	0	-2.9%
Total Commercial	849,180	0.5329	452,528	0.55891	474,615	4.9%
TOTAL CORE	2,973,972	0.52957	1,574,921	0.55891	1,662,196	5.5%

1/ CPUC surcharge of $.00076/therm reflected in rates, except for PG&E and SCE-UEG volumes.

2/ TI and TII sales realigned reducing baseline quantities & rates (AL 1539-G).

APPENDIX C-4

ADOPTED CORE RATES AND REVENUES

CLASS OF SERVICE	ADJUSTED CUST/SALES FORECAST (MTH/CUST)	PRESENT RATES ($/TH &/MO)	PRESENT REVENUES (M$)	ADOPTED RATES ($/TH &/MO)	ADOPTED REVENUES (M$)	ADOPTED RATE CHANGE (%)
	(a)	(b)	(c)	(d)	(e)	(f)
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2/ TI and TII sales realigned reducing baseline quantities & rates (AL 1539-G).

APPENDIX C-5

ADOPTED NONCORE TRANSPORT RATE AND REVENUES

NONCORE CUSTOMER CLASS	ADJUSTED FORECAST DELIVERIES (MTH)	HISTORICAL BILLING DETERMINANTS (MTH/CUST)	PRESENT RATES $/TH OR $/MO	PRESENT REVENUES (M$)	ADOPTED RATE $/TH OR $/MO	ADOPTED REVENUES TOTAL NON-GAS (M$)	ADOPTED RATE CHANGE (%)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
PRIORITY P2B							
Customer Charge		74	156.77 3/	140	207.98	186	32.7%
Demand Charge D1		77,833	0.08844	6,884	0.08503	6,618	-3.9%
Demand Charge D2							
Summer		105,758	0.01513	1,600	0.01033	1,092	-31.7%
Winter		46,638	0.03436	1,602	0.01778	829	-48.3%
Volumetric Charg	76,390		0.04353	3,325	0.04346	3,320	-0.2%
TOT/AVE P2B	76,390		0.17740	13,551	0.15769	12,046	-11.1%
INDUSTRIAL G-IND 1/							
Customer Charge		827	555.88 3/	5,516	519.71	5,157	-6.5%
Demand Charge D1		1,287,932	0.05963	76,799	0.08597	110,719	44.2%
Demand Charge D2							
Summer		1,510,157	0.00671	10,133	0.00718	10,842	7.0%
Winter		884,689	0.02238	19,799	0.01327	11,738	-40.7%
Volumetric Charg	1,276,120		0.04325	55,155 4/	0.04076	52,017	-5.8%
INDUST Net of GC-2	1,276,120		0.13118	167,403	0.14926	190,473	13.8%
GC-2 Industrial	261,770			13,530		14,036	3.7%
	----------		---------	---------	---------	---------	---------
TOTAL INDUSTRIAL	1,537,890		0.11765	180,933	0.13298	204,508	13.0%
UTILITY ELEC GEN 2/							
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O P I N I O N

In this order, we address Pacific Gas and Electric Company's (PG&E) annual cost allocation proceeding (ACAP) application. PG&E filed, on September 15, 1988, this application requesting authority to increase its gas rates by $298.0 million. Of this amount, $141.2 million represents balancing account undercollections that PG&E expected as of December 31, 1988. The remaining $156.8 million is due primarily to forecasted changes in gas costs and throughput. PG&E's total request is $362.0 million, following an update of balancing account undercollections as of February 9, 1989. The application requests certain modifications to the existing Commission program established by previous orders.

I. Summary

This decision grants PG&E a revenue increase in the amount of $154.4 million for the test period, January 1, 1989 through December 31, 1989. Balancing account undercollections represent most of the requested increase. Those undercollections total $205.2 million. The remaining $50.8 million decrease results primarily from forecasted changes in throughput and gas costs. This change in revenue requirement translates to a 5.5% increase in residential rates, and a 4.4% increase in commercial rates. Average noncore transportation rates increase by .1%. Procurement rates for the noncore portfolio are not established in this decision as these are posted and may change bimonthly in response to market conditions.

This decision also addresses methods for forecasting throughput and noncore customer discounts required to keep large industrial users on PG&E's system. Much of the proceeding focused on PG&E's methods and models. In general, we find that PG&E's models do not adequately describe customer behavior in a number of

OPINION

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I. Summary

This decision grants PG&E a revenue increase in the amount of $_____ million for the test period, January 1, 1989 through December 31, 1989. Balancing account undercollections represent most of the requested increase. Those undercollections total $205.2 million. The remaining $____ million decrease results primarily from forecasted changes in throughput and gas costs. This change in revenue requirement translates to a ___% increase in residential rates, and a ___% increase in commercial rates. Average noncore transportation rates increase by __%. Procurement rates for the noncore portfolio are not established in this decision as these are posted and may change bimonthly in response to market conditions.

This decision also addresses methods for forecasting throughput and noncore customer discounts required to keep large industrial users on PG&E's system. Much of the proceeding focused on PG&E's methods and models. In general, we find that PG&E's models do not adequately describe customer behavior in a number of ways. For example, we modify PG&E's models so that they account

OPINION

In this order, we address Pacific Gas and Electric Company's (PG&E) annual cost allocation proceeding (ACAP) application. PG&E filed this application on September 15, 1988, requesting authority to increase its gas rates by $221.6 million. On December 12, 1988, PG&E modified its request to $298.0 million, mainly to reflect changes in oil prices. On February 9, 1989, PG&E modified its request to $290.3 million to update the balancing accounts for recorded January 31, 1989 balances. Of this amount, $111.2 million represents a net increase in balancing account undercollections that PG&E expected as of January 31, 1989. The remaining $179.1 million is due primarily to forecasted changes in gas costs and throughput. The application also requests certain modifications to the existing Commission program established by previous orders.

I. Summary

This decision grants PG&E a revenue increase in the amount of $144.0 million for the test period, January 1, 1989 through December 31, 1989. Balancing account undercollections and forecasted changes in throughput and gas costs represent most of the increase. This change in revenue requirement translates to a 5.6% increase in residential rates, and a 4.7% increase in commercial rates. While some noncore transportation rates increase as much as 12.4% (GIND), average noncore transportation rates decrease by 1.1%. Procurement rates for the noncore portfolio are not established in this decision as these are posted and may change bimonthly in response to market conditions.

This decision also addresses methods for forecasting throughput and noncore customer discounts required to keep large industrial users on PG&E's system. Much of the proceeding focused on PG&E's methods and models. In general, we find that PG&E's models do not adequately describe customer behavior in a number of

ways. For example, we modify PG&E's models so that they account for the effects of demand charges on customer decisions with respect to fuel switching. We also modify the models to take into account the effects of core election on model outputs.

We find that PG&E's discount adjustment model is too complex and inaccessible to the parties, and adopt a simpler and more understandable alternative. To facilitate efforts to improve ACAP modeling, we plan to hold workshops within the next 60 days.

In addition, today's order addresses PG&E's proposed gas and oil price assumptions. We find that an appropriate oil price forecast for the test year is $16 per barrel, and that changes in oil prices do affect gas prices. The adopted core weighted average cost of gas (WACOG) is $1.886 per million British thermal unit (MMBtu). The adopted noncore WACOG is $1.90 per MMBtu.

Today's order incorporates the allocation effects of PG&E's 1989 attrition year increase of $37.18 million for PG&E's gas operations adopted in Resolution G-2838. In general, the order retains the cost allocation and rate design principles established in Decision (D.) 87-12-039.

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A. The Purpose of the ACAP

Today's decision implements PG&E's first ACAP. We established this proceeding in D.87-12-039, which addressed cost allocation and rate design principles based on broad policies set forth in earlier orders.

The Commission developed the ACAP as part of its gas regulation program which seeks to respond to changing market conditions for the gas utilities. In recent years, changes in federal policy and gas markets have required that we reconsider our regulation of the gas utilities in order to make them competitive and to promote efficient market transactions.

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As part of this program, the ACAP allows the utilities to begin the process of moving rates toward cost by allocating costs to cost-causers. The regulatory structure underlying the ACAP places increased risk on the gas utilities and provides them new opportunities in noncore markets.

More specifically, the purpose of the ACAP is to:

o Allocate fixed and variable costs between customer classes

o Forecast gas costs and throughput for the test period

o Amortize balancing account undercollections and overcollections

o Revise rates to reflect changes in throughput and expenses

B. Summary of the Proceeding

PG&E filed its ACAP application on September 15, 1988. It initially requested that the Commission increase its revenue requirement by $221.6 million. On December 12, PG&E modified its request mainly to reflect changes in oil prices. PG&E's December 12 filing increases its original request to $298.0 million. Of this amount, $141.2 million represents expected balancing account undercollections.

PG&E's request is based on a throughput forecast and an estimate of gas costs for the test period, January 1, 1989 to December 31, 1989. Its proposed cost allocation between customer classes is, according to PG&E, consistent with Commission directives in D.87-12-039 and with Senate Bill (SB) 987, which required continuation of the existing cost allocation through January 1, 1991. PG&E's proposed rate design, as modified, would increase residential rates by 12.5% on average, and increase noncore transport rates by an average 22.6%.

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Normalization (TURN), California Industrial Group (CIG), Mission Resources (Mission), California Cogeneration Council (CCC), the California Department of General Services (DGS), Southwest Gas Company (Southwest), and Salmon Resources Ltd. with Mock Resources, Inc. (Salmon/Mock). The testimony of Salmon/Mock regarding unbundled brokerage fees was deferred following issuance of D.88-12-045. Southern California Edison Company (SCE) and Canadian Gas Producers (CGP) filed briefs.

Fourteen days of hearings were held in Phase I of this proceeding. The case was submitted on January 27, 1989.

C. <u>Scope of the Proceeding</u>

A number of parties moved to strike all or portions of the testimony of CIG, Mission, DRA, Southwest, and TURN. All of the motions were granted on the grounds that subject testimony was beyond the scope of this first ACAP proceeding. In some cases, testimony appeared to conflict with SB 987 which directed the Commission to retain existing cost allocation methods until January 1, 1991. We concur with the administrative law judge's (ALJ) ruling that experience with our new program is limited, and that we should consider cost allocation changes only in future ACAP proceedings. We are also committed to complying with SB 987, but recognize that cost allocation which assigns costs to cost causers is an integral component of our new gas regulation program and critical to its ultimate success.

D. <u>Document Production</u>

During the first week of hearings, Salmon/Mock, TURN, and others requested that the ALJ require PG&E to release certain customer-specific data which was used as inputs to PG&E's discount adjustment model. The motion was granted subject to protective order. PG&E appealed the ALJ's ruling on the grounds that the information was too sensitive to release publicly.

Subsequently, PG&E filed, on December 12, modifications to its discount adjustment model which did not use customer-specific inputs. The ALJ withdrew the ruling in recognition that PG&E's case in chief no longer relied upon the customer-specific information.

During hearings, PG&E objected to requests by Salmon/Mock to produce PG&E's contract with Enron, a supplier of gas from the Southwest. The ALJ ordered PG&E to produce the contract because, under our policy, the utilities must document their costs with all appropriate information unless imminent and significant harm would result. Prior to its release of the document, PG&E agreed to have its witness cross-examined on the contract's elements. Following cross-examination, Salmon/Mock withdrew its request for a copy of the contract. We are satisfied with the outcome of this conflict, but remind PG&E that it must provide any information to parties requesting it when the utility uses such information to estimate costs. It is not enough for the utility to assert future costs: they must be documented.

E. Brokerage Fees

On December 9, 1988, the Commission, in D.88-12-045, addressed PG&E's petition for modification of R.88-08-018, noting that the policy issues regarding brokerage fees would be resolved in its procurement rulemaking. Implementation of brokerage fees would be included in this ACAP in a second phase of the proceeding. Accordingly, we will address brokerage fee implementation following additional hearings in this proceeding.

F. Attrition Year Cost Allocations

On December 19, 1988, the Commission issued Resolution G-2838, addressing PG&E's 1989 attrition increase request. That resolution directed PG&E to propose in this ACAP proceeding a simpler method for allocating future attrition year revenue changes. Since many of the parties' original filings did not specifically address this issue, it will be considered in Phase II of this proceeding.

III. Major Issues

Forecasting the gas revenue requirement involves investigation and resolution of many interactive factors. Five major categories of issues were considered in this ACAP.

1. Gas Throughput
2. Cost of Gas
3. Cost Allocation
4. Revenue Requirement
5. Rate Design

A. Gas Throughput

Gas throughput is the total demand for natural gas from the PG&E system, including gas purchased and sold to PG&E's customers and transportation of customer-owned gas on PG&E's system.

PG&E's estimates of throughput included use of two models. One is an econometric (ET) model which was used to determine the effects of such factors as weather, economic activity, and fuel prices on levels of throughput for residential, industrial, and commercial customers. Volumes for enhanced oil recovery (EOR), utility electric generation (UEG), and cogeneration were estimated exogenously (that is, outside the econometric models). PG&E also uses a "discount adjustment model." The discount adjustment (DA) model recognizes that some noncore customers will stay on the PG&E system if they are offered discounts from tariffed rates. Evaluation of the models is presented at the end of this section.

The following summarizes the positions of the parties on methodologies, model inputs, and results.

1. Evaluation of the PG&E Models

PG&E's estimates of throughput include use of two types of models. The ET model forecasts throughput econometrically by estimating the effects of such variables as fuel prices, weather, and economic growth on demand.

The DA model estimates revenues by forecasting the discounts required to keep large customers (P2B, G-IND, and COGEN) on PG&E's system. The DA model is used to develop an average industrial transport rate to input into the ET model, to derive a discount adjustment percent for P2B, G-IND and COGEN, and to calculate forecasted billing determinants to which industrial demand charges will be applied.

Using customer-specific load information, the DA model produces "seed" rates which are input into the econometric throughput model. These seed rates are core customer rates and default transport rates for noncore customers. The DA model also produces an adjusted throughput which does not represent actual forecast values. Instead, the adjusted throughput translates a revenue adjustment--resulting from discounted rates--into a volume adjustment. The information provided by the DA model is based on 1987 usage patterns, scaled downward to reflect expected 1989 market conditions of 1,100 PG&E noncore customer accounts.

The DA model is the more controversial of the two models because of its complexity and due to the effects of its outputs on throughput estimates. The interaction of the two models was also the subject of debate.

a. PG&E

PG&E comments that the purpose of the DA model, conceptually adopted by the Commission in D.87-12-039, is to recognize the value of gas, relative to other fuels, to noncore customers. According to PG&E, estimating customers' willingness to pay in advance frees the Commission from reviewing every negotiated agreement. PG&E recovers revenue requirement based on its negotiating skills and knowledge of the market. PG&E believes the model is simple enough for the parties to understand and has agreed to make the model accessible to the parties.

PG&E's original DA model used customer-specific data to estimate required discounts. PG&E amended its original filing so that customer-specific data was not used as model inputs. The revised showing uses average customer data.

b. CIG

(1) The Models

CIG challenges PG&E's methodology on the grounds that the models systematically underestimate throughput. CIG states that PG&E has an incentive to underforecast noncore industrial throughput in order to lower PG&E's risk of recovery.

CIG cites a number of ways the models together underestimate throughput. The econometric models, according to CIG, are specified in conjunction with the DA model so that an unadjusted throughput forecast of lost load, once made, cannot be regained even when assumptions are changed. The ET model will predict a loss of load that is actually being retained by way of negotiated transmission rates.

Moreover, a reduction in average gas prices or an increase in the premium does not result in a corresponding increase in throughput. When lower gas prices were assumed, the DA model increases the revenues collected from the G-IND class, increasing the discount ratio as well as the average transport rate. The higher discount ratio translates into a higher adjusted throughput for ratemaking purposes, but the higher average industrial transport rate offsets the lower gas costs in the seed rate calculation. Thus, the unadjusted throughput level, which reflects the real level of gas demand, is maintained despite significant reductions in gas costs.

CIG argues that PG&E's DA model does not take into account any potential discounts from gas suppliers in response to competitive pressures. Additionally, since the ET model does not use historic data, it cannot provide reliable estimates of throughput.

Finally, CIG notes that PG&E's use of econometric model outputs as inputs to the DA model, while using DA model outputs as inputs to the econometric model is a circular and self-fulfilling prophecy.

(2) CIG's Proposal

CIG believes the PG&E methodology is so flawed that it should not be used to estimate throughput. CIG recommends instead that the Commission adopt an estimate based on PG&E's most recent recorded annual period.

Under CIG's proposal, the Commission would consider as "unadjusted throughput" PG&E's recorded industrial throughput for the period June 1987 through June 1988. That amount is 1,680 million therms (MMth). According to CIG, this throughput is reasonable because most recent recorded data do not show any evidence of a decline in throughput. Using this throughput does not make the illogical assumption made by PG&E that gas prices will not respond to lower oil prices.

To develop an average discount, the Commission should use the average discounts negotiated by PG&E in current contracts, which is now 61% of the existing default rate. CIG points out that the resulting $.0975 per therm discount rate is comparable to PG&E's existing average G-IND rate of $.098 per therm.

To implement CIG's recommendation, the volumes subject to discounting are estimated. CIG's witness assumed that 700 MMth would be discounted based on the 679 MMth currently under discounted contracts. The 61% discount is then applied to those volumes to yield a "full rate" equivalent volume of 427 MMth. This full rate equivalent volume is then added to the volumes not subject to discounting (that is, the unadjusted throughput less discounted throughput) to yield the discount-adjusted volume to be used for ratemaking purpose. Using the 1.68 MMth as unadjusted throughput, the CIG methodology yields a discount-adjusted throughput of 1,407 MMth.

c. TURN

(1) The Models

TURN observes numerous shortcomings in the DA model. First, TURN states the model improperly applies 1989 market conditions to historical usage patterns even though significant changes in the market have occurred since 1987. For instance, the company's procedure assumes that all cogenerators on line in 1989 will have the same load patterns and alternative fuel costs as those of a much smaller group who were operating in 1987.

TURN believes 1987 data is not representative of 1989 market conditions because that period precedes gas industry restructuring and the introduction of demand charges. For this reason, TURN recommends that the Commission rely on aggregate rather than customer-specific load data for forecasting.

TURN also suggests that in determining the average level of necessary rate discounts, PG&E should use the discount percentage developed for existing contracts and multiply them by the volumes in those agreements. TURN makes this suggestion on the basis that those contracts are the best evidence of the level of discounts actually required by the marketplace and they are already public information.

TURN also challenges the application of the outputs of the DA model to the ET model. According to TURN, PG&E has double-counted load loss of 33 MMth. The ET model predicted 33 MMth of load loss, load which was discounted by the DA model. In effect, according to TURN, rate discounts were found necessary for load already assumed lost in the ET model. Since the ET model does not predict individual customer fuel switching behavior, this problem cannot be corrected.

TURN adds that the fact that Negotiated Revenue Stability Account (NRSA) balances are almost zero for 1988--even though oil prices were well below the assumed level--is evidence that PG&E'S forecasting methods, which were used for the last forecast, are systematically biased. Similarly, the drop in oil prices at the end of 1988 did not lead to significant increases in contract negotiation. PG&E reports that only 80 of its 1,100 industrial customers have so far negotiated contracts. On this basis, TURN believes it is unreasonable to assume that 96% of industrial volumes will be subject to discounted rates during the test period, as PG&E's models predict.

TURN is also critical of the econometric model itself. First, TURN states that for econometric models to work, there must be sufficient historical data. PG&E uses a single average gas price.

Like CIG, TURN observes that the econometric model will assume lost loads that will not actually be lost because it employs an average negotiated rate level instead of a minimum negotiated rate level. This problem, according to TURN, is not remedied by the fact that the historical gas prices used as inputs to the ET model also represent average industrial prices because PG&E has had greater negotiating flexibility since May 1 than it has had in the past. Accordingly, PG&E will sell gas at a wider range of discounted rates than is reflected in the historical data base.

To remedy this problem, TURN recommends that the ET model be run twice, once using the default transmission rate and again using the minimum floor rate. The default transmission rates are the rates noncore customers would pay for transportation absent negotiation. The results of the initial run would establish the forecast of throughput at default rates. The difference between this run and that using the minimum floor rate would represent the additional volumes that could potentially be regained through discounting. TURN's witness stated a simpler approach would be to add an estimated average exit charge to the oil price forecast used in the ET model to reflect the fact that fuel switchers would be paying these costs in addition to the price of the oil itself.

Finally, TURN states a preference for DRA's econometric model over PG&E's because, although the models are similar, DRA's yields a lower forecast error than PG&E's when applied to recent historical data.

(2) TURN's Proposal

TURN recommends that the Commission reject PG&E's DA model, and goes so far as to disassociate itself from PG&E's DA model, which has been referred to conceptually as the "TURN adjustment." TURN proposes a simpler analysis which uses aggregate data for large groups of customers with the same alternative fuel capabilities, rather than individual customer data which TURN states is of dubious reliability.

Under TURN's methodology, the average gas commodity cost would be subtracted from the average alternate fuel price, adjusted to account for effects of demand charges and premiums. This average gas price would be weighted according to relative forecasted usage of the core and noncore WACOGs. If the resulting rate is higher than the expected default rate, no discount would be necessary. If the rate is less than the default rate, a discount would be calculated. This percentage would be multiplied by the forecast of unadjusted throughput for customers with that alternative fuel to determine the appropriate discount adjustment volume, which would be subtracted from the forecast of unadjusted throughput for cost allocation and rate design purposes.

This approach can also be used to derive average transport rates to plug into the ET model by selecting either the "maximum transport rate" or the default rate for each fuel type, weighted by volume, whichever is lower. Percentage splits for each fuel type would have to be determined, and have been developed in the record. In each case, according to TURN, GC-2 or SCE volumes would also have to be factored into the transport seed rate.

TURN states its methodology does not provide results which vary significantly from those provided by PG&E's methodology. The advantage of the TURN model is its simplicity and understandability. It may be used to estimate all noncore class rates and transport rates.

TURN also suggests the Commission hold workshops shortly after this proceeding which would allow the parties to explore the models in more depth.

d. <u>DRA</u>

DRA notes that the PG&E models have created a great deal of confusion in this case and recommends a simpler approach to PG&E's DA model. DRA states that the model cannot be run by the parties and the data base of 1,100 customers is unwieldy. DRA also expresses concern that the customer-specific information in the originally filed model demands a secret review of the results, contrary to the public hearing process.

DRA supports TURN's proposal on the grounds that it is simple, accessible to parties, and can be applied to all utilities. It also incorporates the effects of demand charges and core election. According to DRA it provides reasonable inputs to the econometric model.

DRA is not as confident about CIG's approach in large part because the model does not account for changes in the relationship between gas and oil. DRA is also reluctant to abandon the ET model, as proposed by CIG.

e. <u>CGP</u>

CGP believes there are design flaws in both PG&E's and DRA's models which yield unacceptable results. CGP points out that the models provide counterintuitive results in that when the gas premium is increased in the DA model, the ET model forecasts lower throughput. Both models appear to treat the premium as an additive to the cost of gas rather than to its value to customers.

CGP also states that there exists between the models a circularity problem that occurs because the models cannot be iterated enough times to reconcile the discrepancies between projected revenues and revenue requirements. CGP suggests that the models are not very useful at this time because of their complexity and because of inexperience with them.

CGP proposes that the Commission adopt policy guidelines in this proceeding which will foster development of models which are simpler and more internally consistent. In the interim, CGP recommends adoption of TURN's approach which uses a single set of alternative fuel prices and which does not require complex computer applications.

f. DGS

DGS states that PG&E's econometric industrial forecast is assumed to include all GC-2 sales. The low GC-2 rates, however, are not included in the development of the seed rate by the DA model, resulting in a forecast that is too low. DGS proposes that the Commission correct this error by ordering the econometric model to be run with a final seed rate based on a weighted average of 83% of the seed rate that would otherwise have been developed and 17% of the average GC-2 rate to reflect the percentage GC-2 volumes.

g. Salmon/Mock

Salmon/Mock supports the proposals of CIG and TURN. Salmon/Mock argues that, contrary to D.87-12-039, the PG&E discount model fails to assume that upstream pipelines and producers could be assumed to bear a portion of the burden of discounting.

h. PG&E Rebuttal

PG&E states its methodology is relatively objective. It argues that using existing contracts requires the Commission to make judgments about the reasonableness of the contracts, or else reward utilities that are poor negotiators by allocating less revenues to their noncore class and placing the utilities at less risk. PG&E states that using forecasted rather than historical data in estimating throughput and revenues takes into account expected market changes.

PG&E also states that use of 1987 recorded data is a reasonable way to approximate use in 1988 and 1989 after scaling the data. Use of 1987 recorded billing data, according to PG&E, yields more accurate results than using no individual billing data, contrary to TURN's assertions.

i. <u>Discussion</u>

PG&E has attempted to determine 1989 throughput by looking at economic factors, and following an assessment of noncore volumes which could be retained through discounting transportation rates. PG&E's models are, for the most part, thoughtful and sophisticated. Because this is the first ACAP, PG&E's task was formidable. The concept of a discount adjustment model is new. The risks associated with inaccurate forecasting are considerable under our new regulatory program.

While we commend PG&E's efforts to provide an acceptable framework for determining discounts and throughput, we have serious reservations regarding certain model specifications which have been the subject of much controversy in this proceeding.

Some observations of market behavior demonstrate intuitively the shortcomings of PG&E's model results. As TURN points out, PG&E's industrial throughput has increased from 3,297 MMth in 1986 to 4,602 MMth in 1987 to 5,282 MMth in 1988. PG&E's models predict a severe reversal of this pattern, estimating a drop of over one-third to 3,729 MMth in 1989. As CIG reports, 61% of volumes required discounts in 1988; PG&E's models predict that 96% will require discounts in 1989.

Some of the biases in the models are a result of implausible input assumptions which we will address separately.

Aside from the issue of model inputs, model designs are troublesome. To begin with, the parties observe correctly that PG&E's models and the way they interact are very complex. A great deal of time was spent in the hearings in efforts to understand the most basic inner workings of the discount adjustment model and the way it was used in conjunction with econometric models. The complexity of the models made it difficult to analyze inputs and results. Adding to this source of difficulty is the fact that the parties could not have access to certain customer load information, which is the backbone of the DA model.

The models have other serious technical problems which intervenors identify. Among them is the way the models together appear to double-count some load loss, and the failure of ET model throughput estimates to fall when gas prices assumptions are reduced in the DA model.

Model specifications do not allow an assumption that gas suppliers will be forced by market conditions to discount their product, thus implying that purchasers are without any negotiating power. Curiously, the ET model appears to use little historic data, the very data econometric models are designed to use.

In spite of their apparent sophistication, the ET model and the DA model do not provide results which are consistently logical. Attempting to perfect those models and the way they interact is a task we cannot hope to accomplish in this proceeding. Some adjustments may be made to improve them and we will require those adjustments where appropriate. PG&E's discount adjustment model, however, is not salvageable. It is just too complex and too difficult to use, primarily because of its reliance on customer-specific bill calculations and load information.

We appreciate the efforts of CIG and TURN to develop alternative methods of calculating discounts and throughput. CIG's approach has intuitive appeal because it is simple and uses existing information regarding necessary customer discounts. It requires no econometric modeling or assumptions regarding future gas prices. While CIG's approach is commendable, we are concerned that it is too simple and fails to account for changing relationships between oil and gas prices and other changing market conditions, as DRA points out.

We believe TURN's method is more appropriate. Like the CIG model, it is simple and does not require the use of confidential information. It takes into account historical information and provides results which are intuitively sound. It appropriately accounts for the premium and demand charges. In addition, TURN's model takes advantage of appropriate econometric methods and recognizes forecasted values for gas and alternate fuels. TURN's method is a reasonable alternative to PG&E's DA model, and we will use it in our calculation of required discounts to transport rates for large noncore customers. The TURN formula is presented graphically in Appendix B, Table 1.

Finally, we will make DGS' proposed adjustment to the ET model, which incorporates the lower GC-2 rates in the seed rates. Estimated discounts and discount volumes for industrial customers are presented in Appendix B, Table 1. Adopted throughput is shown in Appendix B, Table 2.

While we endorse TURN's model in this proceeding, we recognize that refinements or changes to it may be appropriate as PG&E and intervenors gain experience with ACAP forecasting and the marketplace. Accordingly, we invite PG&E and other interested parties to propose changes in future ACAPs.

We will entertain model changes under certain conditions. First, we will not estimate throughput, revenues, revenue requirements, or required discounts using data which cannot be reviewed by the parties to the ACAP proceeding. Second, we will be reluctant to revise the conceptual changes we have made, for instance, those regarding the effects of demand charges and core election, discussed below, without a strong showing. Any proposed models or changes to the models should be understandable, simple, and intuitively sound.

At TURN's suggestion, we will direct Commission Advisory and Compliance Division (CACD) to hold workshops on the models adopted in this proceeding within 60 days of the effective date of this decision. The purpose of those workshops will be to help interested parties to understand the models, specifications, and shortcomings. We also hope that the workshops will provide a forum for determining improvements to forecasting methods which may be used in the next ACAP. We strongly encourage other gas utilities to participate in these workshops.

2. Model Assumptions

a. Economic Activity

Activity in the economy is one input in the econometric model. PG&E forecasted a 30% probability of recession in 1989 and weighted its inputs accordingly. DRA argued that PG&E's forecast was too pessimistic, citing Data Resources Inc. (DRI) and the University of California at Los Angeles forecasts of economic activity in the state.

DGS concurs with DRA that we should not assume a recession will occur in 1989. DGS suggests that if the Commission adopts DRA's estimate of economic activity in 1989, it should also adjust the industrial throughput forecast accordingly. DGS suggests using PG&E's higher estimate of a 2.4% increase in industrial production rather than DRA's estimate of 1.4%, to be consistent with a nonrecession forecast.

TURN also supports DRA's estimates of economic activity.

We concur with DRA that most economic observers do not foresee a recession in 1989. We will also adopt DRA's estimate of growth in industrial production as a reasonable corollary to its estimates of economic activity.

b. Alternate Fuel Prices

Fuel prices affect model outcomes and are used in both the discount adjustment model and the econometric model. Higher prices for alternate fuels--propane, Number 2 fuel oil and Number 6 fuel oil--lead to higher throughput, other things equal, because gas prices are relatively more attractive to customers.

(1) Propane

PG&E estimates an average wholesale price for propane of $.282 per therm. PG&E uses a wholesale, rather than delivered, price because propane is costly to transport. Most customers who use propane do not require transport and purchase it at the wholesale rate.

DRA argues that some of PG&E's customers buy propane at delivered prices, and propane price estimates should be weighted accordingly. At DRA's request, PG&E estimated the number of customers who purchase propane at delivered prices to be about 23%. PG&E also presented average delivered rates which are estimated by the Lundberg Company to be $.421 per therm adjusted to 1989 dollars. PG&E characterizes the Lundberg survey as unrealistic, but did not provide alternative estimates of retail propane prices.

We concur with DRA that the estimated propane price for 1989 should be a weighted average of wholesale and retail rates to reflect customers who purchase propane at retail rates. We will use the Lundberg survey in the absence of other reasonable estimates. Accordingly, our adopted propane price is $.314 per therm.

(2) Number 6 Fuel Oil

PG&E estimated significant reductions in oil prices in 1989, down to $14.62 per barrel, or $.196 per therm. PG&E's original application estimated oil prices in 1989 to be $19.12. PG&E reduced this estimate following oil price reductions in late 1988.

DRA estimated crude oil prices would average $17 per barrel during 1989, equal to $.285 per therm for the refiner's acquisition cost, and $.254 per therm for the delivered price. DRA based its estimate on the average refiners' acquisition cost, using EIA's Third Quarter 1988 Short Term Energy Outlook. DRA's estimate attempts to anticipate the effects of OPEC price-setting meetings held during 1988. DRA notes that EIA used a higher OPEC production level than PG&E and still came up with a higher forecasted oil price.

TURN supports DRA's estimate of crude oil prices. TURN points out that the OPEC meeting that established the new quotas took place after both the DRI forecast of $18.30 per barrel and the EIA reduction to $15 per barrel. TURN submits that DRA's estimate is conservative.

TURN also states that the Commission must translate its adopted Number 6 fuel oil price into prices for other products. TURN suggests using DRA's formula to develop appropriate terminal and delivered prices for Number 6 fuel oil.

Generally, Salmon/Mock urges against a forecast of dramatic reductions in fuel prices because such a forecast could have a significant effect on industrial default rates.

PG&E asserts that DRA's estimate is based upon outdated data since the most recent EIA forecasts reduced the 1989 oil price from $17 per barrel to $15 per barrel. PG&E also argues that, contrary to DRA's assumption, OPEC price setting agreements have not been honored in the past.

PG&E's forecast appears to be based as much on current prices as on anticipated prices for the test period. Oil prices have historically fluctuated significantly over short time periods.

We have no reason to believe today's oil prices will continue through 1990. DRA's price forecast, on the other hand, is significantly above 1988 average fuel oil prices. Independent forecasts estimate a range of world oil prices for 1989. Within that range, we believe a reasonable forecast to be $16 per barrel or $.268 per therm for the test period.

(3) Number 2 Fuel Oil

Number 2 fuel oil is used as an input to the DA model. PG&E estimated $.323/therm for this commodity. DRA accepted this estimate, but noted that this price should be reduced if the Number 6 fuel price is reduced. TURN recommends using DRA's formula, which would produce a Number 2 fuel oil price of $.374/therm for Number 2 fuel oil, using DRA's crude oil forecast price of $17 per barrel.

Since we have adopted a forecast price of $16 per barrel for Number 6 fuel oil, we will adopt the corresponding price of $.352 per therm for Number 2 fuel oil.

c. Customer Growth

Both DRA and PG&E use econometric models to forecast customer growth in all major customer classes. The results from these forecasts are included in the econometric throughput model. Differences between their estimates are less than 1%. Since the differences are so small, we will adopt PG&E's estimate.

d. Effects of Demand Charges

PG&E's DA model did not assume that demand charges would affect customer choices regarding whether or not to switch to alternative fuels. A number of parties criticized the model for this omission.

DRA, CIG, and TURN argue that customers will surely consider these "exit costs" in their fuel switching decisions. Customers do not have infinitely long time horizons, as PG&E assumes. Instead, the model should assume a shorter term planning horizon. CIG points to PG&E's testimony to argue that demand charges have the effect of increasing a customer's alternate fuel price.

Similarly, CGP and Salmon/Mock criticize the omission of demand charges as one variable which would influence switching decisions. DGS goes further to suggest that each of the major gas utilities be required to submit a methodology for incorporating demand charges in future forecasts.

CIG proposes, based on a review of PG&E's contracts, that exit costs averaged $.03 per therm in 1989. For default agreements, estimated exit costs would be about $.05 per therm. CIG proposes that these amounts be added to the cost of alternate fuels in the DA model. CIG also supports TURN's methodology as a sound alternative. TURN would apply half of the D-1 charge plus all of the fully ratcheted D-2, at 100% load factor.

In response, PG&E states that the DA model does not calculate load loss; it calculates discounts necessary to retain load. In addition, PG&E argues that including exit charges as an assumption in the DA model is inconsistent with the way rates are negotiated with customers because transport rates are based on estimates of alternate fuel prices plus a premium.

According to PG&E, incorporating demand charge effects in a one-year test period is a difficult task. PG&E's assumption that customers look at gas use as an annual decision is most reasonable. PG&E states that it would like to study the CIG and TURN proposals.

Demand charges present real costs to customers. Accordingly, it is reasonable to assume that customers would include demand charges in calculating their most economic fuel options.

We will adopt CIG's recommendation to add $.03 per therm to the cost of alternate fuels for volumes associated with negotiated contracts and $.05 per therm to the cost of alternate fuels for volumes associated with default agreements. While this method provides only a rough proxy of exit costs, it is a conservative estimate which assumes customers make choices on an annual basis. It is simple and intuitively sound. PG&E should, in its next ACAP, propose a more precise method for estimating the effects of exit costs. Finally, we note that if PG&E is negotiating contracts without taking into account the effects of demand charges, as it seems to state, it may be losing revenue unnecessarily.

e. Gas Premium

The DA model includes a premium for gas to reflect its value to customers relative to the value of alternate fuels.

PG&E requests that the $.02 per therm premium on gas, adopted in D.87-12-039, be reduced to $.017 per therm. PG&E states that it has made this assumption because of changed customer perceptions with regard to service reliability, caused by curtailments last winter on the Southern California Gas Company (SoCal) gas system.

DRA, DGS, CIG, and TURN recommended against this change. DGS points out that the PG&E witness testified that lowering the premium creates a perception of shortage among customers, even though PG&E does not anticipate curtailments. Thus, the reduced premium is a self-fulfilling prophecy.

PG&E also proposes eliminating the premium assumed for GC-2 customers whose contracts expire in 1989. This change is reasonable, according to PG&E, because it expects some resistance from these customers as they realize the impact of higher rates resulting from this ACAP.

DGS argues that this change is inappropriate because the premium is set to reflect the value of gas over oil in all circumstances.

We will not change the premium since PG&E has not demonstrated that the existing amount is unreasonable. We are not convinced that customer perceptions regarding reliability have changed. In addition, we believe the premium should be assumed for all GC-2 customers. The DA model and ET model are designed to capture the effects of higher rates on the attractiveness of gas. Eliminating the premium results in double-counting necessary discounts to customers.

f. Effects of Core Election

TURN is critical of the DA model because it does not weight core and noncore gas prices to reflect the fact that large users may buy gas at either core prices (as core elect customers) or noncore gas prices. Without this weighting, the model will predict that discounting will be required to keep customers on the system who already realize a rate below the noncore WACOG.

DRA agrees with TURN that the DA model ignores core election even though approximately 55% of industrial throughput is estimated to be core elect. This oversight, according to DRA, is a transparent attempt by PG&E to lower its risk by ignoring what it expects to occur during the forecast period.

Like TURN, DRA proposes the DA model recognize the effects of core election by way of one of two model adjustments. The model could incorporate a weighted average of core and noncore portfolio prices. Alternatively, the model specifications could be changed so that in calculating each customer's bill, either the core or noncore WACOG would be used depending upon whether or not the customer is a core-elect customer. DRA states that the latter option may be difficult to accomplish in this case because of time constraints.

CGP and Salmon/Mock support DRA and TURN's position on this issue.

PG&E responds that the DA model should use a single benchmark price in order to avoid having the noncore transportation revenue responsibility depend on customer procurement choices. PG&E states that in some cases the core WACOG may be above the noncore WACOG, increasing the revenue allocation to the noncore.

We agree with DRA and TURN that the DA model should reflect the fact that some noncore customers elect core status. The effect of using PG&E's assumption does not exclusively affect revenue allocation between classes as PG&E seems to assume. It also affects the amount of risk allocated between shareholders and

alternative fuels. A number of parties criticized the model for this omission.

DRA, CIG, and TURN argue that customers will surely consider these "exit costs" in their fuel switching decisions. Customers do not have infinitely long time horizons, as PG&E assumes. Instead, the model should assume a shorter term planning horizon. CIG points to PG&E's testimony to argue that demand charges have the effect of increasing a customer's alternate fuel price.

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CIG proposes, based on a review of PG&E's contracts, that exit costs averaged $.03 per therm in 1989. For default agreements, estimated exit costs would be about $.05 per therm. CIG proposes that these amounts be added to the cost of alternate fuels in the DA model. CIG also supports TURN's methodology as a sound alternative. TURN would apply half of the D-1 charge plus all of the fully ratcheted D-2, at 100% load factor.

In response, PG&E states that the DA model does not calculate load loss; it calculates discounts necessary to retain load. In addition, PG&E argues that including exit charges as an assumption in the DA model is inconsistent with the way rates are negotiated with customers because transport rates are based on estimates of alternate fuel prices plus a premium.

According to PG&E, incorporating demand charge effects in a one-year test period is a difficult task. PG&E's assumption that customers look at gas use as an annual decision is most reasonable. PG&E states that it would like to study the CIG and TURN proposals.

Demand charges present real costs to customers. Accordingly, it is reasonable to assume that customers would ratepayers as it affects revenue estimates from the noncore class. Incorporating DRA's and TURN's proposal would provide a more realistic estimate of noncore revenue. PG&E also states that alternative approaches would not comply with the Commission's stated goal of keeping transport and procurement rates independent of each other. We do not agree with PG&E that the effect of making this forecast model adjustment would be to change service arrangements for transport and procurement. PG&E confuses forecast assumptions with actual changes in rate structures.

We will adjust the DA model to incorporate adopted estimates of core elect throughput. A more extensive change in model specifications, as DRA suggests, may be appropriate in future ACAPs.

3. Throughput Estimates

Throughput estimates include all gas, whether procured by the utility or the customer, transported through utility pipelines. Throughput estimates affect rates: the higher the estimate of throughput, the more volumes over which to spread fixed costs. Throughput estimates also affect the level of risk borne by the utility: higher estimates increase the risk of revenue recovery.

a. Industrial

Using its ET model, PG&E estimated industrial throughput for the test period to be 1,231 MMth. The difference between DRA's and PG&E's estimates of industrial throughput is about 13.5%. This difference is mainly due to differing model specifications regarding demand elasticity and DRA's higher estimate for fuel oil. PG&E argues that DRA's elasticity assumptions are unrealistic because industrial demand has not increased at a proportionately higher rate than industrial growth in recent years.

DRA estimates a 1.5% increase in throughput for a 1% change in industrial activity. PG&E estimates a .9% increase in throughput for a 1% increase in activity.

include demand charges in calculating their most economic fuel options.

We will adopt CIG's recommendation to add $.03 per therm to the cost of alternate fuels for volumes associated with negotiated contracts and $.05 per therm to the cost of alternate fuels for volumes associated with default agreements. Weighting these amounts according to usage, the adjustment to the model is $0.044. While this method provides only a rough proxy of exit costs, it is a conservative estimate which assumes customers make choices on an annual basis. It is simple and intuitively sound. PG&E should, in its next ACAP, propose a more precise method for estimating the effects of exit costs. Finally, we note that if PG&E is negotiating contracts without taking into account the effects of demand charges, as it seems to state, it may be losing revenue unnecessarily.

e. <u>Gas Premium</u>

The DA model includes a premium for gas to reflect its value to customers relative to the value of alternate fuels.

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DRA, DGS, CIG, and TURN recommended against this change. DGS points out that the PG&E witness testified that lowering the premium creates a perception of shortage among customers, even though PG&E does not anticipate curtailments. Thus, the reduced premium is a self-fulfilling prophecy.

PG&E also proposes eliminating the premium assumed for GC-2 customers whose contracts expire in 1989. This change is reasonable, according to PG&E, because it expects some resistance

TURN challenges PG&E's industrial throughput estimates. TURN points out that PG&E's forecast of 1,231 MMth is substantially below its 1988 year end projection of 1,591 MMth and follows a steady increase in load since 1986. TURN argues that model assumptions and specifications, discussed in more detail below, systematically underestimate throughput by at least 30 MMth, in addition to other model shortcomings.

DGS asserts that PG&E incorrectly assigns all cogeneration gas use to the G-COG rate. PG&E admits that the G-COG tariff currently limits gas sold under the G-COG rate to 9,300 Btu per kilowatt-hour (kWh). DGS' witness testified that the average cogeneration project uses about 10,250 Btu per kWh or 30 MMth per year, which DGS proposes should be assigned to the G-IND rate. This 30 MMth per year should be subtracted from the G-COG unadjusted throughput and added to the industrial unadjusted throughput since that gas would be sold under the G-IND rate. The incremental cogeneration calculation does not require this correction, according to DGS. TURN makes the same proposal.

TURN also notes that PG&E incorrectly attributed half of cogeneration usage to gas needed to generate steam. TURN points out that DGS' witness testified that about 30% of cogeneration gas is used for industrial uses. Accordingly, TURN recommends the difference of 104 MMth be added to industrial throughput.

With regard to DGS' proposed 30 MMth cogeneration adjustment, PG&E replies that DGS failed to subtract out the cogeneration volumes which are GC-2 loads. The result would be a total adjustment of 18 MMth.

We will not rule on values for demand elasticity since demand elasticity is a product, not an input, to the econometric model. They are determined according to various model assumptions. In general, we will use PG&E's specifications for the econometric model, modified by changes in inputs and assumptions as discussed elsewhere in this order. We will also make the from these customers as they realize the impact of higher rates resulting from this ACAP.

DGS argues that this change is inappropriate because the premium is set to reflect the value of gas over oil in all circumstances.

We will not change the premium since PG&E has not demonstrated that the existing amount is unreasonable. We are not convinced that customer perceptions regarding reliability have changed. In addition, we believe the premium should be assumed for GC-2 customers after expiration of their contracts. The DA model and ET model are designed to capture the effects of higher rates on the attractiveness of gas. Eliminating the premium results in double-counting necessary discounts to customers.

f. Effects of Core Election

TURN is critical of the DA model because it does not weight core and noncore gas prices to reflect the fact that large users may buy gas at either core prices (as core elect customers) or noncore gas prices. Without this weighting, the model will predict that discounting will be required to keep customers on the system who already realize a rate below the noncore WACOG.

DRA agrees with TURN that the DA model ignores core election even though approximately 55% of industrial throughput is estimated to be core elect. This oversight, according to DRA, is a transparent attempt by PG&E to lower its risk by ignoring what it expects to occur during the forecast period.

Like TURN, DRA proposes the DA model recognize the effects of core election by way of one of two model adjustments. The model could incorporate a weighted average of core and noncore portfolio prices. Alternatively, the model specifications could be changed so that in calculating each customer's bill, either the core or noncore WACOG would be used depending upon whether or not the customer is a core-elect customer. DRA states that the latter adjustments to the industrial throughput and cogeneration throughput forecasts recommended by TURN and DGS, except that we will subtract 18 MMth from that adjustment to reflect PG&E's correction. The adjustments provide a more accurate forecast. The adopted industrial throughput will also be adjusted for changes in other inputs and model specifications presented elsewhere in this order.

b. Utility Electric Generation (UEG)

PG&E estimated UEG throughput exogenously as 1,387 MMth for the test period. This estimate is based on average hydro year conditions.

DRA accepts PG&E's estimates for PG&E's own UEG throughput as consistent with the assumptions adopted in its recent Energy Cost Adjustment Clause (ECAC) proceeding. DRA's estimate for SCE throughput is 933 mega-decatherm higher than PG&E's. DRA based its forecast on the results of its production cost model run in the latest SCE ECAC proceeding.

TURN recommends using the forecast adopted in the current ECAC proceeding, at least for the first seven months of 1989. TURN believes the data in the ECAC has been more fully scrutinized in ECAC hearings than it could have been in this proceeding.

TURN also proposes that the Commission adopt a provision to reflect increased UEG gas usage occurring as a result of a shutdown of Rancho Seco. TURN's proposal provides for an alternative gas cost allocation if the plant is shut down so that non-UEG customers are protected from the vagaries of electric resource availability. A similar mechanism was adopted in PG&E's most recent ECAC order.

PG&E responds that the UEG forecast proposed by TURN reflects dry hydro conditions of 1988 for the first five months of the forecast. PG&E points to D.87-12-039, which stated that UEG forecast should be based on an average hydro year.

option may be difficult to accomplish in this case because of time constraints.

CPG and Salmon/Mock support DRA and TURN's position on this issue.

PG&E responds that the DA model should use a single benchmark price in order to avoid having the noncore transportation revenue responsibility depend on customer procurement choices. PG&E states that in some cases the core WACOG may be above the noncore WACOG, increasing the revenue allocation to the noncore.

We agree with DRA and TURN that the DA model should reflect the fact that some noncore customers elect core status. The effect of using PG&E's assumption does not exclusively affect revenue allocation between classes as PG&E seems to assume. It also affects the amount of risk allocated between shareholders and ratepayers as it affects revenue estimates from the noncore class. Incorporating DRA's and TURN's proposal would provide a more realistic estimate of noncore revenue. PG&E also states that alternative approaches would not comply with the Commission's stated goal of keeping transport and procurement rates independent of each other. We do not agree with PG&E that the effect of making this forecast model adjustment would be to change service arrangements for transport and procurement. PG&E confuses forecast assumptions with actual changes in rate structures.

We will adjust the DA model to incorporate adopted estimates of core elect throughput. A more extensive change in model specifications, as DRA suggests, may be appropriate in future ACAPs.

3. <u>Throughput Estimates</u>

Throughput estimates include all gas, whether procured by the utility or the customer, transported through utility pipelines. Throughput estimates affect rates: the higher the estimate of throughput, the more volumes over which to spread fixed costs.

We agree with DRA that ECAC expense estimates should be used to the extent they are current, and that they should be updated using methodologies adopted in ECAC proceedings. Estimates, however, should continue to be based on an average hydro year, as we stated in D.87-12-039. Accordingly, we will adopt DRA's estimates of UEG throughput since they are consistent with PG&E and SCE's ECAC review estimates and methodologies.

SCE proposes that its Cool Water plant be classified and treated as a UEG plant in this proceeding because it produces electricity, not industrial products. PG&E has provided no justification for treating Cool Water as an industrial plant. PG&E responds that since Cool Water is a combined cycle plant, the plant is unlike any of PG&E's electrical plants. PG&E states that SCE is able to negotiate rates like any other customer if it is dissatisfied with the UEG rate.

We will not grant SCE's request to reclassify Cool Water at this time. The scope of this proceeding does not anticipate such customer reclassifications. SCE is an able negotiator and has the opportunity to negotiate its gas rates with PG&E if it is dissatisfied with PG&E's industrial rates.

As to TURN's proposal for a reallocation of fixed costs during Rancho Seco shutdowns, we will not further complicate the ACAP proceeding with another allocation mechanism unless it is truly warranted. We are especially hesitant to undertake a twice-yearly allocation process. Some risk of a mismatch between forecasted and actual values is expected. The risk of misallocation because of unanticipated Rancho Seco shutdowns, however, is not great enough to make the program change proposed by TURN.

c. <u>Enhanced Oil Recovery (EOR)</u>

PG&E estimates, based on market information rather than an econometric model, a large reduction in throughput to the

Throughput estimates also affect the level of risk borne by the utility: higher estimates increase the risk of revenue recovery.

a. Industrial

Using its ET model, PG&E estimated industrial throughput for the test period to be 1,231 MMth. The difference between DRA's and PG&E's estimates of industrial throughput is about 13.5%. This difference is mainly due to differing model specifications regarding demand elasticity and DRA's higher estimate for fuel oil. PG&E argues that DRA's elasticity assumptions are unrealistic because industrial demand has not increased at a proportionately higher rate than industrial growth in recent years.

DRA estimates a 1.5% increase in throughput for a 1% change in industrial activity. PG&E estimates a .9% increase in throughput for a 1% increase in activity.

TURN challenges PG&E's industrial throughput estimates. TURN points out that PG&E's forecast of 1,231 MMth is substantially below its 1988 year end projection of 1,591 MMth and follows a steady increase in load since 1986. TURN argues that model assumptions and specifications, discussed in more detail below, systematically underestimate throughput by at least 30 MMth, in addition to other model shortcomings.

DGS asserts that PG&E incorrectly assigns all cogeneration gas use to the G-COG rate. PG&E admits that the G-COG tariff currently limits gas sold under the G-COG rate to 9,300 Btu per kilowatt-hour (kWh). DGS' witness testified that the average cogeneration project uses about 10,250 Btu per kWh or 30 MMth per year, which DGS proposes should be assigned to the G-IND rate. This 30 MMth per year should be subtracted from the G-COG unadjusted throughput and added to the industrial unadjusted throughput since that gas would be sold under the G-IND rate. The incremental cogeneration calculation does not require this correction, according to DGS. TURN makes the same proposal.

EOR market as a result of lower oil prices. For 1989, PG&E estimates 232 MMth of EOR throughput.

DRA states that PG&E's original estimate of 373 MMth is reasonable. TURN agrees with DRA that the original estimate is reasonable on the grounds that PG&E's lower forecast resulted from lower priced oil. If the Commission adopts a crude oil price of $17 per barrel, EOR throughput should be estimated at 373 MMth.

PG&E responds that its original estimate was based on an oil price considerably higher than DRA's oil price estimate of $17. DRA acknowledges that EOR throughput is a function of oil prices but cannot defend its higher throughput estimate on that basis.

We will adopt DRA's proposal since, as discussed in other portions of this order, we do not forecast a drastic decline in oil prices or the differential between oil and gas prices PG&E proposes.

d. Interutility

PG&E's updated filing assumes 202 MMth (or 53 million cubic feet (MMcf) per day of interutility transport. Its estimate assumes that no gas will be sold off-system by PG&E to Southern California customers from PG&E's noncore portfolio at the noncore WACOG. PG&E bases its estimate on 1988 off-system transport volumes which averaged 42 MMcf per day, not including interutility transport of customer-owned gas.

DRA supports PG&E's original estimate of 673 MMth (or 176 MMcf per day) on the grounds that the recent large reduction in interutility throughput occurred as a result of the drop in oil prices which are again increasing. DRA states that if its oil price estimate of $17 is adopted, the original PG&E interutility transport estimate should also be adopted. TURN supports DRA's position.

TURN also notes that PG&E incorrectly attributed half of cogeneration usage to gas needed to generate steam. TURN points out that DGS' witness testified that about 30% of cogeneration gas is used for industrial uses. Accordingly, TURN recommends the difference of 104 MMth be added to industrial throughput.

With regard to DGS' proposed 30 MMth cogeneration adjustment, PG&E replies that DGS failed to subtract out the cogeneration volumes which are GC-2 loads. The result would be a total adjustment of 18 MMth.

We will not rule on values for demand elasticity since demand elasticity is a product, not an input, to the econometric model. They are determined according to various model assumptions. In general, we will use PG&E's specifications for the econometric model, modified by changes in inputs and assumptions as discussed elsewhere in this order. We will also make the adjustments to the industrial throughput and cogeneration throughput forecasts recommended by TURN and DGS, except that we will subtract 18 MMth from that adjustment to reflect PG&E's correction. The adjustments provide a more accurate forecast. The adopted industrial throughput will also be adjusted for changes in other inputs and model specifications presented elsewhere in this order.

b. <u>Utility Electric Generation (UEG)</u>

PG&E estimated UEG throughput exogenously as 1,387 MMth for the test period. This estimate is based on average hydro year conditions.

DRA accepts PG&E's estimates for PG&E's own UEG throughput as consistent with the assumptions adopted in its recent Energy Cost Adjustment Clause (ECAC) proceeding. DRA's estimate for SCE throughput is 933 mega-decatherm higher than PG&E's. DRA based its forecast on the results of its production cost model run in the latest SCE ECAC proceeding.

TURN recommends using the forecast adopted in the current ECAC proceeding, at least for the first seven months of 1989. TURN

Based on our findings regarding gas prices, oil prices, and their interrelationship, we will adopt DRA's forecast of 673 MMth for the test period.

e. Residential and Commercial

PG&E and DRA estimates of residential and commercial throughput are very close. Our adopted estimates of residential and commercial throughput are determined according to changes in model specifications and assumptions determined elsewhere in this order.

f. Cogeneration

PG&E developed its estimates of cogeneration throughput exogenously by adding throughput from projects it expects to come on line during the forecast period to recorded December 1987 cogeneration usage.

As discussed under the discussion of industrial throughput, PG&E's estimate of cogeneration throughput will be adjusted to reflect the changes proposed by DGS and TURN. With these adjustments, we will adopt PG&E's estimate of cogeneration throughput.

B. Cost of Gas

1. Effects of Oil Prices on Gas Prices

A major controversy arose during the proceeding regarding the relationship between oil and gas prices. PG&E estimated that the cost of oil would significantly decrease during the forecast period, making oil a more attractive alternative to noncore customers and thereby reducing gas throughput estimates. PG&E did not assume gas prices would fall as a response to the lower cost of alternative fuels.

DRA, TURN, CIG, Salmon/Mock, CGP, and DGS argued that the cost of gas is influenced substantially by the cost of oil and other alternative fuels.

CIG's witness testified that a reduction in oil prices puts pressure on gas prices as users switch to fuel oil. The believes the data in the ECAC has been more fully scrutinized in ECAC hearings than it could have been in this proceeding.

TURN also proposes that the Commission adopt a provision to reflect increased UEG gas usage occurring as a result of a shutdown of Rancho Seco. TURN's proposal provides for an alternative gas cost allocation if the plant is shut down so that non-UEG customers are protected from the vagaries of electric resource availability. A similar mechanism was adopted in PG&E's most recent ECAC order.

PG&E responds that the UEG forecast proposed by TURN reflects dry hydro conditions of 1988 for the first five months of the forecast. PG&E points to D.87-12-039, which stated that UEG forecast should be based on an average hydro year.

We agree with DRA that ECAC expense estimates should be used to the extent they are current, and that they should be updated using methodologies adopted in ECAC proceedings. Estimates, however, should continue to be based on an average hydro year, as we stated in D.87-12-039. Accordingly, we will adopt DRA's estimates of UEG throughput since they are consistent with PG&E and SCE's ECAC review estimates and methodologies.

SCE proposes that its Cool Water plant be classified and treated as a UEG plant in this proceeding because it produces electricity, not industrial products. PG&E has provided no justification for treating Cool Water as an industrial plant. PG&E responds that since Cool Water is a combined cycle plant, the plant is unlike any of PG&E's electrical plants. PG&E states that SCE is able to negotiate rates like any other customer if it is dissatisfied with the UEG rate.

We will not grant SCE's request to reclassify Cool Water at this time. The scope of this proceeding does not anticipate such customer reclassifications. SCE is an able negotiator and has the opportunity to negotiate its gas rates with PG&E if it is dissatisfied with PG&E's industrial rates.

estimated reduction of crude oil prices to $14.62 should force spot gas prices at the California border down to $1.88 per MMBtu, in contrast to PG&E's estimate of $2.20 per MMBtu. CIG arrived at its estimate by applying a "rule of thumb" used by energy forecasters to equate the cost of oil to the cost of gas. CIG also applied a DRI energy forecast model to check its estimated cost of gas.

CIG observes that the relationship between gas and oil prices has historically not been a precise 10:1 ratio. Rather, on average, the ratio represents a reasonable equilibrium relationship.

CGP agrees that it is wrong to assume there is no relationship between gas and oil prices, although it does not support CIG's use of a 10:1 ratio. CGP urges the Commission to use a "rule of reason" rather than a "rule of thumb" and not be constrained between the extreme proposals of PG&E and CIG.

DGS proposes that the Commission consider a six-month forecast twice a year, since the volatility of oil prices increases risks to customers and the utility. Alternatively, the Commission should assume at least that gas prices do follow oil prices to some extent.

TURN also challenges PG&E's assumption that gas prices will not fall in response to lower oil prices. The major objective of industry restructuring is to promote competition among gas supplies and between gas and oil suppliers. It is counterproductive to assume that every dip in oil prices must be matched by a discount in utility gas prices, and gas producers will not drop their prices if PG&E will absorb necessary discounts for them. PG&E's assumptions, according to TURN, may result in a self-fulfilling prophecy which will work to the detriment of all California gas consumers.

In response, PG&E criticizes CIG's gas cost estimate by arguing that the "rule of thumb" is not a refined method for estimating future gas prices and that DRI does not rely on such

As to TURN's proposal for a reallocation of fixed costs during Rancho Seco shutdowns, we will not further complicate the ACAP proceeding with another allocation mechanism unless it is truly warranted. We are especially hesitant to undertake a twice-yearly allocation process. Some risk of a mismatch between forecasted and actual values is expected. The risk of misallocation because of unanticipated Rancho Seco shutdowns, however, is not great enough to make the program change proposed by TURN.

c. Enhanced Oil Recovery (EOR)

PG&E estimates, based on market information rather than an econometric model, a large reduction in throughput to the EOR market as a result of lower oil prices. For 1989, PG&E estimates 232 MMth of EOR throughput.

DRA states that PG&E's original estimate of 373 MMth is reasonable. TURN agrees with DRA that the original estimate is reasonable on the grounds that PG&E's lower forecast resulted from lower priced oil. If the Commission adopts a crude oil price of $17 per barrel, EOR throughput should be estimated at 373 MMth.

PG&E responds that its original estimate was based on an oil price considerably higher than DRA's oil price estimate of $17. DRA acknowledges that EOR throughput is a function of oil prices and defends its higher throughput estimate on that basis.

We will adopt DRA's proposal since we have adopted DRA's oil price estimate.

d. Interutility

PG&E's updated filing assumes 202 MMth per day (or 53 million cubic feet (MMcf) per year) of interutility transport. Its estimate assumes that no gas will be sold off-system by PG&E to Southern California customers from PG&E's noncore portfolio at the noncore WACOG. PG&E bases its estimate on 1988 off-system transport volumes which averaged 42 MMcf per day, not including interutility transport of customer-owned gas.

ratios. PG&E points to CIG witness' testimony that the 10:1 ratio has not held up historically and that DRI does not use such ratios in its forecasts.

Much debate centered on whether CIG's estimated wellhead prices included the El Paso gathering charge of $.34. PG&E argued that they did not, and showed that when the $.34 gathering charge is added to CIG's price estimate, that estimate exceeded PG&E's. CIG responded that its wellhead price did include gathering costs.

On brief, CIG noted that if the Commission adopts CIG's throughput forecast methodology, the Commission need not determine forecasted oil and gas prices. The output of PG&E's models requires such determinations. Since the models are, according to CIG, unreliable forecasting tools, there is no reason to forecast specific gas and oil price levels.

We agree with the parties who propose that a significant reduction in oil costs is likely to result in lower gas prices. Our new regulatory framework is based in large part on an assumption that competition between alternate fuels exists. PG&E's own case makes that assumption. Where such competition exists, price changes occurring for one product are likely to affect prices of substitutes. While no consistent historical relationship between oil and gas is apparent, it is clear that oil prices affect gas prices over time. Industry experts agree that this relationship exists. Our determinations of gas price forecasts in the following discussion will be made with this relationship in mind.

We are surprised that PG&E has refused to recognize such a relationship in this proceeding. Assuming lower forecasted oil prices, PG&E's assumptions regarding gas prices for the forecast period are unrealistic.

2. <u>Core WACOG</u>

The core portfolio contains all long-term supplies and any short-term supplies needed to meet demand. In this

DRA supports PG&E's original estimate of 673 MMth (or 176 MMcf per day) on the grounds that the recent large reduction in interutility throughput occurred as a result of the drop in oil prices which are again increasing. DRA states that if its oil price estimate of $17 is adopted, the original PG&E interutility transport estimate should also be adopted. TURN supports DRA's position.

Based on our findings regarding gas prices, oil prices, and their interrelationship, we will adopt DRA's forecast of 673 MMth for the test period.

e. Residential and Commercial

PG&E and DRA estimates of residential and commercial throughput are very close. Our adopted estimates of residential and commercial throughput are determined according to changes in model specifications and assumptions determined elsewhere in this order.

f. Cogeneration

PG&E developed its estimates of cogeneration throughput exogenously by adding throughput from projects it expects to come on line during the forecast period to recorded December 1987 cogeneration usage.

As discussed under the discussion of industrial throughput, PG&E's estimate of cogeneration throughput will be adjusted to reflect the changes proposed by DGS and TURN. With these adjustments, we will adopt PG&E's estimate of cogeneration throughput.

B. Cost of Gas

1. Effects of Oil Prices on Gas Prices

A major controversy arose during the proceeding regarding the relationship between oil and gas prices. PG&E estimated that the cost of oil would significantly decrease during the forecast period, making oil a more attractive alternative to noncore customers and thereby reducing gas throughput estimates. PG&E did application, PG&E estimated its core portfolio WACOG to be $1.92 in 1989. DRA estimated the core WACOG to be $1.87.

Much of the debate regarding gas costs centered around prices for gas from California sources and Southwest suppliers, which together make up about a quarter of total supplies. Overall, DRA does not expect the price of short-term supplies to increase during the forecast period. PG&E expects increases for California and Southwest supplies. Appendix B, Table 3 provides our adopted forecasts of gas prices and volumes from various supply sources.

a. <u>California Supplies</u>

PG&E estimates California supplies will average $1.85/MMBtu during the test period based on the price it is currently paying for small volumes of California gas. DRA believes California supplies will average $1.70/MMBtu, which is the present negotiated price for California gas. DRA does not believe California gas prices will rise as a result of upcoming contract negotiations with California supplies, given the fall in oil prices.

TURN states that PG&E's estimate is probably inevitable, given the recent legislative intervention into PG&E's relationship with California producers.

Salmon/Mock supports the PG&E estimate on the grounds that PG&E has already negotiated an increased price with some producers and because PG&E currently intends to offer an increased price of $1.85/MMBtu to all California producers.

We are not convinced that the California price will rise to $1.85/MMBtu, given lower world oil prices. Nevertheless, some increase appears likely since PG&E is already paying $1.85 MMBtu for some gas. We will adopt $1.80/MMBtu as a reasonable estimate of prices for California gas.

b. <u>Rocky Mountain Supplies</u>

PG&E estimates Rocky Mountain supplies will be $1.67/MMBtu. DRA accepts PG&E's price and volume estimates. CIG not assume gas prices would fall as a response to the lower cost of alternative fuels.

DRA, TURN, CIG, Salmon/Mock, CPG, and DGS argued that the cost of gas is influenced substantially by the cost of oil and other alternative fuels.

CIG's witness testified that a reduction in oil prices puts pressure on gas prices as users switch to fuel oil. The estimated reduction of crude oil prices to $14.62 should force spot gas prices at the California border down to $1.88 per MMBtu, in contrast to PG&E's estimate of $2.20 per MMBtu. CIG arrived at its estimate by applying a "rule of thumb" used by energy forecasters to equate the cost of oil to the cost of gas. CIG also applied a DRI energy forecast model to check its estimated cost of gas.

CIG observes that the relationship between gas and oil prices has historically not been a precise 10:1 ratio. Rather, on average, the ratio represents a reasonable equilibrium relationship.

CPG agrees that it is wrong to assume there is no relationship between gas and oil prices, although it does not support CIG's use of a 10:1 ratio. CPG urges the Commission to use a "rule of reason" rather than a "rule of thumb" and not be constrained between the extreme proposals of PG&E and CIG.

DGS proposes that the Commission consider a six-month forecast twice a year, since the volatility of oil prices increases risks to customers and the utility. Alternatively, the Commission should assume at least that gas prices do follow oil prices to some extent.

TURN also challenges PG&E's assumption that gas prices will not fall in response to lower oil prices. The major objective of industry restructuring is to promote competition among gas supplies and between gas and oil suppliers. It is counterproductive to assume that every dip in oil prices must be matched by a discount in utility gas prices, and gas producers will proposes a Rocky Mountain price of $1.35/MMBtu, based on its analysis of the effects of oil prices on gas prices. We will adopt a price of $1.67/MMBtu because it is the rate currently on file with the Federal Energy Regulatory Commission (FERC).

c. <u>El Paso Supplies</u>

There is no dispute with PG&E's assumption that El Paso supplies will be too expensive to be purchased economically during the test period. We will not assume any supplies from El Paso during 1989.

d. <u>PGT Supplies</u>

PG&E estimates a border price of $1.847/MMBtu, which is the rate in the currently effective PGT general rate case before FERC. DRA concurs with this estimate. CIG proposes a Canadian price of $1.61/MMBtu, based on its forecast of falling gas prices generally. We will adopt PG&E's estimate since it is the rate currently in effect.

e. <u>Southwest Supplies</u>

PG&E estimates the cost of Southwest supplies to be $2.20/MMBtu during the test period. DRA estimates Southwest supplies will average $2.03/MMBtu, which is the average price during the period October 1987 through September 1988. DRA bases its estimate, in part, on DRI forecasts which predict an almost equal probability of a slight rise in oil prices and a sharp decrease in oil costs. Following PG&E's divulging some price information in its contract with ENRON, DRA modified its estimate upward to $2.13/MMBtu.

PG&E criticizes DRA's estimate because it assumes 1987 prices will remain constant through 1990 and fails to take into account El Paso's general rate case.

Similarly, Salmon/Mock believes DRA's estimate is too low given that 50% of PG&E's Southwest supplies will be purchased under long-term contracts at $2.30/MMBtu.

not drop their prices if PG&E will absorb necessary discounts for them. PG&E's assumptions, according to TURN, may result in a self-fulfilling prophecy which will work to the detriment of all California gas consumers.

In response, PG&E criticizes CIG's gas cost estimate by arguing that the "rule of thumb" is not a refined method for estimating future gas prices and that DRI does not rely on such ratios. PG&E points to CIG witness' testimony that the 10:1 ratio has not held up historically and that DRI does not use such ratios in its forecasts.

Much debate centered on whether CIG's estimated wellhead prices included the El Paso gathering charge of $.34. PG&E argued that they did not, and showed that when the $.34 gathering charge is added to CIG's price estimate, that estimate exceeded PG&E's. CIG responded that its wellhead price did include gathering costs.

On brief, CIG noted that if the Commission adopts CIG's throughput forecast methodology, the Commission need not determine forecasted oil and gas prices. The output of PG&E's models requires such determinations. Since the models are, according to CIG, unreliable forecasting tools, there is no reason to forecast specific gas and oil price levels.

We agree with the parties who propose that a significant reduction in oil costs is likely to result in lower gas prices. Our new regulatory framework is based in large part on an assumption that competition between alternate fuels exists. PG&E's own case makes that assumption. Where such competition exists, price changes occurring for one product are likely to affect prices of substitutes. While no consistent historical relationship between oil and gas is apparent, it is clear that oil prices affect gas prices over time. Industry experts agree that this relationship exists. Our determinations of gas price forecasts in the following discussion will be made with this relationship in mind.

DRA responds that the effects of the El Paso rate case cannot be inferred from PG&E's data. To this, TURN adds that the El Paso rate increase is subject to refund, and that it is wrong to assume that gas purchasers, as opposed to producers, will bear all of the increase. TURN also adjusted its estimate of Southwest gas prices--to $2.15/MMBtu--after PG&E presented information about its long-term agreements.

Half of PG&E's Southwest gas is purchased at $2.30. Consequently, the average price of Southwest supplies would be $2.20/MMBtu if half of the supplies averaged $2.10 MMBtu. We find this amount high for spot gas given world oil prices. We also agree with TURN that the effects of the El Paso rate increase should not be assumed to fall entirely on purchasers. We will assume an average price for Southwest gas of $2.10. This amount assumes that Southwest spot prices will be, on average, $1.90.

f. <u>Volumes from the PGT Line</u>

Significant controversy arose during the hearings regarding capacity on PG&E's interstate lines. PG&E estimates Canadian gas takes of 878 MMcf/day (or 320 Bcf) in 1989, an amount significantly below total capacity and considerably less than actual throughput in 1988. These estimates result in higher total gas costs since Southwest gas is more expensive than Canadian gas.

DRA, Salmon/Mock, TURN, CGP, and CIG argue that PG&E is underestimating the volume of takes on its PGT line and overestimating those from the El Paso line.

CGP agrees that reduced throughput over the PGT line could occur if PG&E's throughput estimates are adopted. It argues, however, that constraints which would block full utilization of PGT's capacity under any scenario have not been demonstrated. CGP points out that PG&E has, in the pending PGT rate case at FERC, stipulated to an estimate of 1,000 MMcf/day, well above PG&E's estimate in this case. CGP also comments that PG&E should have a special burden to demonstrate that it cannot carry greater volumes

We are surprised that PG&E has refused to recognize such a relationship in this proceeding. Assuming lower forecasted oil prices, PG&E's assumptions regarding gas prices for the forecast period are unrealistic.

2. Core WACOG

The core portfolio contains all long-term supplies and any short-term supplies needed to meet demand. In this application, PG&E estimated its core portfolio WACOG to be $1.92 in 1989. DRA estimated the core WACOG to be $1.87.

Much of the debate regarding gas costs centered around prices for gas from California sources and Southwest suppliers, which together make up about a quarter of total supplies. Overall, DRA does not expect the price of short-term supplies to increase during the forecast period. PG&E expects increases for California and Southwest supplies. Appendix B, Table 3 provides our adopted forecasts of gas prices and volumes from various supply sources.

a. California Supplies

PG&E estimates California supplies will average $1.85/MMBtu during the test period based on the price it is currently paying for small volumes of California gas. DRA believes California supplies will average $1.70/MMBtu, which is the present negotiated price for California gas. DRA does not believe California gas prices will rise as a result of upcoming contract negotiations with California supplies, given the fall in oil prices.

TURN states that PG&E's estimate is probably inevitable, given the recent legislative intervention into PG&E's relationship with California producers.

Salmon/Mock supports the PG&E estimate on the grounds that PG&E has already negotiated an increased price with some producers and because PG&E currently intends to offer an increased price of $1.85/MMBtu to all California producers.

over the PGT line given its pending proposal at the CPUC to expand its existing system.

DGS also points out that PG&E is ignoring the PGT rate case, and that PG&E is currently operating the PGT pipeline at full capacity. The Commission, according to DGS, should assume that the PGT pipeline will operate at full capacity year round.

Salmon/Mock agrees that PG&E has not provided evidence to demonstrate that it cannot operate the PGT line at full capacity. Salmon/Mock proposes that the Commission adopt a forecast which allocates 60 MMcf/day for noncore customers in the northern portion of PG&E's system and 60 MMcf/day of interutility transportation of Canadian gas for customers in southern California, in addition to the 878 MMcf/day forecast by PG&E.

PG&E responds that it cannot increase PGT takes without reducing below minimum capacity levels the takes from the El Paso line. PG&E also states that at higher volumes estimated by DRA, it must pay higher commodity costs for PGT gas because of increased compressor fuel usage.

We agree with the parties who argue that PG&E has not demonstrated why it can transport less than the maximum capacity over the PGT line during the test period. PG&E's witness testified that average deliveries on the PGT line were 1,009 MMcf/day during January through November 1988. PG&E forecasts no transport of Canadian gas over the PGT pipeline in 1989, and Canadian gas is less expensive than Southwest gas. We also note that PG&E has stipulated to forecasts of full capacity over the PGT pipeline in the PGT rate case. Accordingly, we will adopt an estimate of 1,009 MMcf/day of Canadian gas over the PGT pipeline for the test period.

3. Noncore WACOG

As we determined in D.87-12-039, the noncore portfolio contains only short-term supplies with prices that are firm for up to 30 days. PG&E estimated a noncore WACOG of $2.20 per MMBtu for

Since PG&E is already paying $1.85 MMBtu for some gas, we will adopt that amount as a reasonable estimate of prices for California gas.

b. Rocky Mountain Supplies

PG&E estimates Rocky Mountain supplies will be $1.67/MMBtu. DRA accepts PG&E's price and volume estimates. CIG proposes a Rocky Mountain price of $1.35/MMBtu, based on its analysis of the effects of oil prices on gas prices. We will adopt a price of $1.67/MMBtu because it is the rate currently on file with the Federal Energy Regulatory Commission (FERC).

c. El Paso Supplies

There is no dispute with PG&E's assumption that El Paso supplies will be too expensive to be purchased economically during the test period. We will not assume any supplies from El Paso during 1989.

d. PGT Supplies

PG&E estimates a border price of $1.847/MMBtu, which is the rate in the currently effective PGT general rate case before FERC. DRA concurs with this estimate. CIG proposes a Canadian price of $1.61/MMBtu, based on its forecast of falling gas prices generally.

Since the record was submitted in this case, Canadian producers filed an application with the Canadian National Energy Board (NEB) to increase the commodity rate to $1.90/MMBtu. The NEB approved the rate on a temporary basis. We do not expect this rate to go below $1.90/MMBtu, since some producers are seeking a higher price and PGT has accepted the $1.90/MMBtu price. We will take official notice of NEB ruling and adopt $1.90/MMBtu, adjusted to $1.94/MMBtu at the California border, for the Canadian gas price.

e. Southwest Supplies

PG&E estimates the cost of Southwest supplies to be $2.20/MMBtu during the test period. DRA estimates Southwest

1989, mainly on the basis of estimates of Southwest gas spot prices.

DRA forecasts a noncore WACOG of $1.97 based upon a 12-month historical average of spot prices at the California border provided in the reports of Natural Gas Week. DRA states PG&E's estimate relies too heavily on recent winter prices, which tend to be higher than average annual prices. As discussed above, DRA states the effects of the El Paso rate case on Southwest supplies cannot be inferred from PG&E's data. TURN supports DRA's position.

CIG estimated the noncore WACOG to be $1.82 for reasons presented in the previous section on the effects of oil price changes on gas prices.

We will adopt a noncore WACOG of $1.90, consistent with our forecast of prices for Southwest spot supplies. Although $1.90 is slightly below 1988 spot gas prices, we believe the reduction in oil prices will continue to drive down the price of spot gas. We note that spot gas prices fell significantly during fall 1988 following oil price reductions. We also find that the adopted noncore WACOG is conservative in light of our forecast oil price, and bears a reasonable relationship to it.

4. <u>Transition Costs</u>

In D.87-12-039, we determined that transition costs are those which:

- Took effect before December 3, 1986;
- Were incurred for the benefit of all ratepayers;
- Were intended to be recouped from all ratepayers;
- Result in costs in excess of a currently reasonable level.

Among those costs recognized as transition costs are El Paso liquids, Order 94/270 costs, take-or-pay for Rocky Mountain and Canadian supplies, GEDA costs, and storage demand charges.

supplies will average \$2.03/MMBtu, which is the average price during the period October 1987 through September 1988. DRA bases its estimate, in part, on DRI forecasts which predict an almost equal probability of a slight rise in oil prices and a sharp decrease in oil costs. Following PG&E's divulging some price information in its contract with ENRON, DRA modified its estimate upward to \$2.13/MMBtu.

PG&E criticizes DRA's estimate because it assumes 1987 prices will remain constant through 1990 and fails to take into account El Paso's general rate case.

Similarly, Salmon/Mock believes DRA's estimate is too low given that 50% of PG&E's Southwest supplies will be purchased under long-term contracts at \$2.30/MMBtu.

DRA responds that the effects of the El Paso rate case cannot be inferred from PG&E's data. To this, TURN adds that the El Paso rate increase is subject to refund, and that it is wrong to assume that gas purchasers, as opposed to producers, will bear all of the increase. TURN also adjusted its estimate of Southwest gas prices--to \$2.15/MMBtu--after PG&E presented information about its long-term agreements.

Half of PG&E's Southwest gas is purchased at \$2.30. Consequently, the average price of Southwest supplies would be \$2.20/MMBtu if the other half of the supplies averaged \$2.10 MMBtu. We find this amount high for spot gas given world oil prices. We also agree with TURN that the effects of the El Paso rate increase should not be assumed to fall entirely on purchasers. We will assume an average price for Southwest gas of \$2.10. This amount assumes that Southwest spot prices will be, on average, \$1.90.

f. <u>Volumes from the PGT Line</u>

Significant controversy arose during the hearings regarding capacity on PG&E's interstate lines. PG&E estimates Canadian gas takes of 878 MMcf/day (or 320 Bcf per year) in 1989, an amount significantly below total capacity and considerably less

Most transition costs were not disputed by the parties. In those cases, we adopt PG&E's estimates as reasonable. Disputed issues are discussed below.

a. <u>Storage-Related Costs</u>

PG&E estimates storage-related transition costs based on an annual forecast. DRA forecasts these costs based on a monthly average because storage-related costs are booked monthly on the basis of monthly core WACOGs and average industry values. DRA believes forecasting accuracy requires an estimate of seasonal spot price variations. PG&E responds that the differences in estimates are largely due to differing gas price forecasts, but that DRA's methodology is contrary to that developed in D.87-12-039 and is subject to greater uncertainty.

We agree with PG&E that we should not change our methodology at this time. We will use PG&E's approach of weighting average annual gas costs, based on the costs we adopt in this order.

b. <u>El Paso Filings at FERC</u>

PG&E proposes to establish an interest-bearing deferred debit account to track potential new transition costs which may result from FERC resolution of various El Paso filings. PG&E proposes that disposition of any account balances be considered in its next ACAP.

CGP agrees with PG&E's proposal to defer resolution of this issue until after FERC's ruling is final. TURN argues that PG&E should not be granted interest for these extraordinary costs. DRA does not take issue with PG&E's position but notes that the quantification and method for recovering take-or-pay obligations will become highly controversial when they are known.

We will adopt PG&E's proposal to establish a deferred debit account, which will be considered in PG&E's next ACAP. At that time we will also determine the appropriateness of recovery of interest on the balance.

than actual throughput in 1988. These estimates result in higher total gas costs since Southwest gas is more expensive than Canadian gas.

DRA, Salmon/Mock, TURN, CPG and CIG argue that PG&E is underestimating the volume of takes on its PGT line and overestimating those from the El Paso line.

CPG agrees that reduced throughput over the PGT line could occur if PG&E's throughput estimates are adopted. It argues, however, that constraints which would block full utilization of PGT's capacity under any scenario have not been demonstrated. CPG points out that PG&E has, in the pending PGT rate case at FERC, stipulated to an estimate of 1,000 MMcf/day, well above PG&E's estimate in this case. CPG also comments that PG&E should have a special burden to demonstrate that it cannot carry greater volumes over the PGT line given its pending proposal at the CPUC to expand its existing system.

DGS also points out that PG&E is ignoring the PGT rate case, and that PG&E is currently operating the PGT pipeline at full capacity. The Commission, according to DGS, should assume that the PGT pipeline will operate at full capacity year round.

Salmon/Mock agrees that PG&E has not provided evidence to demonstrate that it cannot operate the PGT line at full capacity. Salmon/Mock proposes that the Commission adopt a forecast which allocates 60 MMcf/day for noncore customers in the northern portion of PG&E's system and 60 MMcf/day of interutility transportation of Canadian gas for customers in southern California, in addition to the 878 MMcf/day forecast by PG&E.

PG&E responds that it cannot increase PGT takes without reducing below minimum capacity levels the takes from the El Paso line. PG&E also states that at higher volumes estimated by DRA, it must pay higher commodity costs for PGT gas because of increased compressor fuel usage.

5. EOR and GC-2 Revenues

PG&E estimates $4.1 million credit from the EOR market. DRA's forecasts $6.9 million, mainly as a result of differing EOR forecasts. PG&E urges that if the Commission adopts PG&E's EOR forecast, it should adopt its EOR credit.

TURN points out that PG&E's revenue estimates do not include escalation rates which are included in contracts with EOR and GC-2 customers.

Because we have adopted DRA's estimate of EOR throughput, we will adopt DRA's associated forecast of EOR credits in the amount of $6.9 million. We agree with TURN that a more accurate estimate of EOR and GC-2 revenues would include escalation factors. We will adjust the EOR and GC-2 revenues using escalation factors of 6.1% and 3.738%, respectively, and expect PG&E to present escalated numbers in the future.

C. Cost Allocation

Cost allocation is the process of assigning fixed and variable costs to various customer classes. PG&E's core customers include residential, small commercial, and large commercial customers. The remainder, including industrial, UEG, cogeneration and wholesale customers, are noncore customers.

1. Variable Costs

The primary variable cost to PG&E is the cost of gas. Under the Commission's new regulatory framework, large customers may elect to purchase gas directly from suppliers or brokers and have PG&E transport the gas. Alternatively, such customers may continue to purchase gas from the utility at tariffed rates, which may change every two weeks to reflect price and market changes.

PG&E is at risk for any mismatch that occurs between noncore costs and rates except in the case of certain levels of NRSA balances which are recoverable for two years following implementation of our program. Core prices, on the other hand, do not change frequently to reflect changes in gas costs. PG&E

We agree with the parties who argue that PG&E has not demonstrated why it can transport less than the maximum capacity over the PGT line during the test period. PG&E's witness testified that average deliveries on the PGT line were 1,009 MMcf/day during January through November 1988. PG&E forecasts no transport of Canadian gas over the PGT pipeline in 1989, and Canadian gas is less expensive than Southwest gas. We also note that PG&E has stipulated to forecasts of full capacity over the PGT pipeline in the PGT rate case. Accordingly, we will adopt an estimate of 1,009 MMcf/day of Canadian gas over the PGT pipeline for the test period.

3. Noncore WACOG

As we determined in D.87-12-039, the noncore portfolio contains only short-term supplies with prices that are firm for up to 30 days. PG&E estimated a noncore WACOG of $2.20 per MMBtu for 1989, mainly on the basis of estimates of Southwest gas spot prices.

DRA forecasts a noncore WACOG of $1.97 based upon a 12-month historical average of spot prices at the California border provided in the reports of Natural Gas Week. DRA states PG&E's estimate relies too heavily on recent winter prices, which tend to be higher than average annual prices. As discussed above, DRA states the effects of the El Paso rate case on Southwest supplies cannot be inferred from PG&E's data. TURN supports DRA's position.

CIG estimated the noncore WACOG to be $1.82 for reasons presented in the previous section on the effects of oil price changes on gas prices.

We will adopt a noncore WACOG of $1.90, consistent with our forecast of prices for Southwest spot supplies. Although $1.90 is slightly below 1988 spot gas prices, we believe the reduction in oil prices will continue to drive down the price of spot gas. We note that spot gas prices fell significantly during fall 1988 following oil price reductions. We also find that the adopted accounts for differences between rates and costs in its Purchased Gas Adjustment Account (PGA), a balancing account which relieves PG&E of any risk associated with core gas costs.

PG&E proposes, and DRA concurs, that PGA account balances should be allocated on an equal-cents-per-therm basis to both core and core elect customers.

PG&E's proposed treatment of PGA balances is consistent with our previous orders and will be adopted.

2. Fixed Costs

Fixed costs are those which are relatively stable and are generally incurred notwithstanding the volumes of gas flowing through the utility's system.

In D.86-12-009 and subsequent orders, we established cost allocation principles for PG&E's fixed costs. PG&E does not propose any changes to adopted methods for allocating fixed costs. Such costs include those associated with distribution, transmission, storage, and administrative and general expenses.

a. Negotiated Revenue Stability Account (NRSA) Balances

The NRSA tracks recovery of revenues associated with fixed costs allocated to the noncore market. As of November 1988, the NRSA balance was zero. During periods when the balance is negative, PG&E proposes that NRSA undercollections be allocated on an equal-cents-per-therm basis to all customer classes. It uses this method because its result approximates the same result that would have occurred had the original estimates of revenues and expenses been correct.

DRA proposes that they be based on an equal percentage of fixed cost revenue. DRA makes this recommendation because the Commission has traditionally used such an allocation method for fixed cost underrecovery. DRA believes the equal percentage of fixed cost allocation approximates the rate structure that would have resulted if noncore throughput had been correctly forecast.

noncore WACOG is conservative in light of our forecast oil price, and bears a reasonable relationship to it.

4. Transition Costs

In D.87-12-039, we determined that transition costs are those which:

- Took effect before December 3, 1986;
- Were incurred for the benefit of all ratepayers;
- Were intended to be recouped from all ratepayers;
- Result in costs in excess of a currently reasonable level.

Among those costs recognized as transition costs are El Paso liquids, Order 94/270 costs, take-or-pay for Rocky Mountain and Canadian supplies, GEDA costs, and storage demand charges. Most transition costs were not disputed by the parties. In those cases, we adopt PG&E's estimates as reasonable. Disputed issues are discussed below.

a. Storage-Related Costs

PG&E estimates storage-related transition costs based on an annual forecast. DRA forecasts these costs based on a monthly average because storage-related costs are booked monthly on the basis of monthly core WACOGs and average industry values. DRA believes forecasting accuracy requires an estimate of seasonal spot price variations. PG&E responds that the differences in estimates are largely due to differing gas price forecasts, but that DRA's methodology is contrary to that developed in D.87-12-039 and is subject to greater uncertainty.

We agree with PG&E that we should not change our methodology at this time. We will use PG&E's approach of weighting average annual gas costs, based on the costs we adopt in this order.

It also mitigates the destabilizing effects of increasing large customer rates.

DGS supports DRA's proposed allocation since it mimics the actual cost allocation which would have occurred if the demand forecast had been correct.

CIG proposes that NRSA balances be allocated only to core customers. To allocate these balances to the noncore will only exacerbate the problem that created the undercollection. As a matter of fairness, the NRSA balance should not be allocated to the noncore because those who will end up paying for it will be default customers: other noncore customers will be able to negotiate around it.

TURN recommends that the entire balance be initially allocated to the noncore market on an equal-cents-per-therm basis. TURN argues that the DA model will end up allocating certain fixed costs to core customers anyway, and noncore customers will never pay more than their value of service. It would be unfair for core customers to pay noncore fixed costs through the allocation of NRSA balances and through the discount adjustment process, especially when the costs involved were originally allocated to the noncore class. TURN also argues that core fixed costs are allocated only to core. As a matter of fairness TURN believes the entire NRSA balance should be allocated to the noncore.

We will adopt PG&E's methodology because we believe it approximates the same result that would have occurred had original estimates of revenues and expenses been correct. We reject TURN's proposal because it would effectively change our allocation methodology, assuming NRSA undercollections occurred because of a mismatch between forecast assumptions and actual experience.

b. <u>Take-or-Pay Transition Costs</u>

Take-or-pay transition costs are allocated on an equal-cents-per-therm basis and are recovered through volumetric rates.

b. El Paso Filings at FERC

PG&E proposes to establish an interest-bearing deferred debit account to track potential new transition costs which may result from FERC resolution of various El Paso filings. PG&E proposes that disposition of any account balances be considered in its next ACAP.

CPG agrees with PG&E's proposal to defer resolution of this issue until after FERC's ruling is final. TURN argues that PG&E should not be granted interest for these extraordinary costs. DRA does not take issue with PG&E's position but notes that the quantification and method for recovering take-or-pay obligations will become highly controversial when they are known.

We will adopt PG&E's proposal to establish a deferred debit account, with interest, which will be considered in PG&E's next ACAP.

5. EOR and GC-2 Revenues

PG&E estimates $4.1 million credit from the EOR market. DRA's forecasts $6.9 million, mainly as a result of differing EOR forecasts. PG&E urges that if the Commission adopts PG&E's EOR forecast, it should adopt its EOR credit.

TURN points out that PG&E's revenue estimates do not include escalation rates which are included in contracts with EOR and GC-2 customers.

Because we have adopted DRA's estimate of EOR throughput, we will adopt DRA's associated forecast of EOR credits in the amount of $6.9 million. We agree with TURN that a more accurate estimate of EOR and GC-2 revenues would include escalation factors. We will adjust the EOR and GC-2 revenues using escalation factors of 6.1% and 3.738%, respectively, and expect PG&E to present escalated numbers in the future.

C. Cost Allocation

Cost allocation is the process of assigning fixed and variable costs to various customer classes. PG&E's core customers

b. El Paso Filings at FERC

PG&E proposes to establish an interest-bearing deferred debit account to track potential new transition costs which may result from FERC resolution of various El Paso filings. PG&E proposes that disposition of any account balances be considered in its next ACAP.

CPG agrees with PG&E's proposal to defer resolution of this issue until after FERC's ruling is final. TURN argues that PG&E should not be granted interest for these extraordinary costs. DRA does not take issue with PG&E's position but notes that the quantification and method for recovering take-or-pay obligations will become highly controversial when they are known.

We will adopt PG&E's proposal to establish a deferred debit account, with interest, which will be considered in PG&E's next ACAP.

5. EOR and GC-2 Revenues

PG&E estimates $4.1 million credit from the EOR market. DRA's forecasts $6.9 million, mainly as a result of differing EOR forecasts. PG&E urges that if the Commission adopts PG&E's EOR forecast, it should adopt its EOR credit.

TURN points out that PG&E's revenue estimates do not include escalation rates which are included in contracts with EOR and GC-2 customers.

Because we have adopted DRA's estimate of EOR throughput, we will adopt DRA's associated forecast of EOR credits in the amount of $6.9 million. We agree with TURN that a more accurate estimate of EOR and GC-2 revenues would include escalation factors. We will adjust the EOR and GC-2 revenues using escalation factors of 3.4% and 3.738%, respectively, and expect PG&E to present escalated numbers in the future.

C. Cost Allocation

Cost allocation is the process of assigning fixed and variable costs to various customer classes. PG&E's core customers

In D.87-12-039, we recognized that the potential magnitude of these costs could require alternate treatment.

In this case, these costs are very small. Accordingly, we will continue the current method of recovering them.

3. EOR Revenues

PG&E proposes to allocate EOR revenues by an equal percentage of base fixed costs or margin. As DRA points out, we required, in D.87-12-039, that such costs be allocated on an equal percentage of fixed costs. We will not change this allocation principle at this time. For the purposes of allocating EOR revenues we use DRA's definition of fixed costs as the collective sum of base revenue fixed costs, interutility credits, pipeline demand charges, gas storage carrying costs, LUAF and GDU expenses, as shown in Appendix B, Table 6 and detailed in part in Appendix B, Table 7.

4. Cogeneration Shortfall Account

a. Allocation of Undercollections

The Cogeneration Shortfall Account (CSA) is a balancing account established to account for a revenue shortfall occurring when cogenerators pay less than the average UEG rate because their otherwise applicable rate is temporarily lower. There is no undercollection in the CSA at this time.

PG&E recommends allocating CSA balances to all customers. DRA and CCC object to this allocation and point out that the Commission, in D.87-05-046, directed that shortfalls should be distributed to the UEG class to promote efficient production of electricity and on grounds of equity.

TURN proposes elimination of this account on the grounds that it provides too much protection to the utility. If it is not eliminated, TURN proposes that undercollections be recovered from UEG and cogeneration customers.

SCE supports PG&E's proposal on the grounds that this "subsidy" to cogenerators is based on the presumed benefits of more include residential, small commercial, and large commercial customers. The remainder, including industrial, UEG, cogeneration and wholesale customers, are noncore customers.

1. Variable Costs

The primary variable cost to PG&E is the cost of gas. Under the Commission's new regulatory framework, large customers may elect to purchase gas directly from suppliers or brokers and have PG&E transport the gas. Alternatively, such customers may continue to purchase gas from the utility at tariffed rates, which may change every two weeks to reflect price and market changes.

Core prices, on the other hand, do not change frequently to reflect changes in gas costs. PG&E accounts for differences between rates and costs in its Purchased Gas Adjustment Account (PGA), a balancing account which relieves PG&E of any risk associated with core gas costs.

PG&E proposes, and DRA concurs, that PGA account balances should be allocated on an equal-cents-per-therm basis to both core and core elect customers.

PG&E's proposed treatment of PGA balances is consistent with our previous orders and will be adopted.

2. Fixed Costs

Fixed costs are those which are relatively stable and are generally incurred notwithstanding the volumes of gas flowing through the utility's system. PG&E is at risk for any mismatch that occurs between noncore costs and rates except in the case of certain levels of NRSA balances which are recoverable for two years following implementation of our program.

In D.86-12-009 and subsequent orders, we established cost allocation principles for PG&E's fixed costs. PG&E does not propose any changes to adopted methods for allocating fixed costs. Such costs include those associated with distribution, transmission, storage, and administrative and general expenses.

efficient overall gas usage through the cogeneration process. Since those benefits accrue to all customers, all customers should pay the subsidy.

We will adopt DRA and CCC's recommendation to allocate shortfalls to the UEG class for the reasons we adopted this practice in D.87-05-046. In response to SCE's comments, we believe it more appropriate to price services based on cost in order to send appropriate signals regarding use rather than to allocate costs on the basis of incidental and widely dispersed benefits of a technology.

We will not eliminate this account at this time, as TURN suggests. However, we believe that as PG&E's competitive posture improves under our new regulatory program, it may be appropriate to eliminate this and similar accounts designed to protect the utility during this transition period.

b. <u>Proposed Accounting Change to CSA</u>

PG&E requests that the Commission approve a modification to the CSA. Under its proposal, PG&E would book the difference between revenues at the adopted average UEG rate and the average rate actually paid. Under existing practice, PG&E books the difference between cogeneration revenues at the actual UEG average rate and the otherwise applicable schedule, whenever the latter is lower.

PG&E argues that the current accounting method leads to a shortfall because of differences between forecasted revenues and actual revenues occurring due to weather. Under our rules, cogenerators may purchase gas out of either UEG tariffs or otherwise applicable rates. During a dry year, rates for the UEG class fall below those forecasted (because demand is higher and fixed costs are spread over larger volumes than expected). When UEG rates are lower than other rates applicable to cogenerators, those customers use the UEG rate, leading to a shortfall from them.

a. <u>Negotiated Revenue Stability Account (NRSA) Balances</u>

The NRSA tracks recovery of revenues associated with fixed costs allocated to the noncore market. As of November 1988, the NRSA balance was zero. During periods when the balance is negative, PG&E proposes that NRSA undercollections be allocated on an equal-cents-per-therm basis to all customer classes. It uses this method because its result approximates the same result that would have occurred had the original estimates of revenues and expenses been correct.

DRA proposes that they be based on an equal percentage of fixed cost revenue. DRA makes this recommendation because the Commission has traditionally used such an allocation method for fixed cost underrecovery. DRA believes the equal percentage of fixed cost allocation approximates the rate structure that would have resulted if noncore throughput had been correctly forecast. It also mitigates the destabilizing effects of increasing large customer rates.

DGS supports DRA's proposed allocation since it mimics the actual cost allocation which would have occurred if the demand forecast had been correct.

CIG proposes that NRSA balances be allocated only to core customers. To allocate these balances to the noncore will only exacerbate the problem that created the undercollection. As a matter of fairness, the NRSA balance should not be allocated to the noncore because those who will end up paying for it will be default customers: other noncore customers will be able to negotiate around it.

TURN recommends that the entire balance be initially allocated to the noncore market on an equal-cents-per-therm basis. TURN argues that the DA model will end up allocating certain fixed costs to core customers anyway, and noncore customers will never pay more than their value of service. It would be unfair for core

PG&E forecasts that it will lose about $5.0 million between May and December 1988 as a result of this effect. Accordingly, PG&E requests that the Commission "smooth the year-to-year effects of the adopted cost allocation and rate design policies on cogeneration gas transportation revenues" which occur because of weather. In the alternative, PG&E states forecasting QF gas prices would take care of the problem. This approach is being discussed between PG&E and QFs.

Other parties to the proceeding object to PG&E's proposal. TURN points out that during a dry year, PG&E may lose revenues from cogenerators, but its revenues from UEG customers increase. DRA objects to the proposal because the modification would reduce risk to PG&E and increase risk for its ratepayers. According to DRA, PG&E is already protected from underrecovery of noncore revenues by way of the NRSA account and that potential losses during some years would be offset during others. PG&E should not be granted increased regulatory protections six months after the new program has been put into place. CCC and DGS also oppose PG&E's proposal.

We will not adopt PG&E's proposal. We agree with DRA and TURN that the modification effectively shifts risk from PG&E to core customers. The risk PG&E currently bears for a cogeneration shortfall is not excessive and is offset by potential gains from UEG customers during a dry year. Further, the probability of losses in some years is offset by the probability of gains in others.

We remind PG&E that our program was developed to provide improved incentives for efficiency for PG&E and additional opportunities to benefit from competition. Increased protections in gas markets will only be granted where significant harm would otherwise result to shareholders or ratepayers. Whether QF gas prices are based on a forecast is an issue which may be considered in other Commission proceedings and we need not address it here.

customers to pay noncore fixed costs through the allocation of NRSA balances and through the discount adjustment process, especially when the costs involved were originally allocated to the noncore class. TURN also argues that core fixed costs are allocated only to core. As a matter of fairness TURN believes the entire NRSA balance should be allocated to the noncore.

We will allocate all NRSA balances to the noncore, as TURN suggests. We believe this allocation is fair because we have allocated all core fixed cost balances to the core. By so doing, we do not change allocations between the core and noncore.

b. Take-or-Pay Transition Costs

Take-or-pay transition costs are allocated on an equal-cents-per-therm basis and are recovered through volumetric rates. In D.87-12-039, we recognized that the potential magnitude of these costs could require alternate treatment.

In this case, these costs are very small. Accordingly, we will continue the current method of recovering them.

3. EOR Revenues

PG&E proposes to allocate EOR revenues by an equal percentage of base fixed costs or margin. As DRA points out, we required, in D.87-12-039, that such costs be allocated on an equal percentage of fixed costs, that is, base costs plus pipeline demand charges. We will not change this allocation principle at this time.

4. Cogeneration Shortfall Account

a. Allocation of Undercollections

The Cogeneration Shortfall Account (CSA) is a balancing account established to account for a revenue shortfall occurring when cogenerators pay less than the average UEG rate because their otherwise applicable rate is temporarily lower. There is no undercollection in the CSA at this time.

PG&E recommends allocating CSA balances to all customers. DRA and CCC object to this allocation and point out that the

5. Oil Burn Credit for Cogenerators

DGS proposed a mechanism to address the effects of economic oil burns on cogeneration rates. Under current policy, PG&E switches from gas to oil whenever oil is cheaper than the incremental cost of gas (even though oil may be more expensive than the core WACOG). As throughput drops, cogeneration gas rates increase to pick up fixed costs allocated to UEG and cogeneration customers.

DGS proposes that during months when economic oil burns occur, the cogeneration gas rate should be developed by dividing gas fixed costs by throughput including both gas and oil burned for economic reasons. According to DGS, such a mechanism would put cogenerators in the same position as they would be in if PG&E operated under a "two-company" policy. Under a two-company policy, PG&E would burn oil only when the oil price was less than the core-elect WACOG, resulting in fewer oil burns.

PG&E objects to DGS's proposal on the grounds that the Commission has recognized that the actual average rate paid by UEG customers (and therefore cogeneration customers) will vary monthly according to many factors, including weather conditions. DGS' proposal, according to PG&E, is one-sided and insulates cogenerators from one factor that can increase their rates. If UEG rates are higher than otherwise applicable rates, cogenerators may switch schedules.

SCE also objects to DGS' proposal. SCE states the distortion between cogenerator and UEG rates is not due to the "one-company" policy but rather due to distortions caused by PG&E's demand charges.

We will not grant DGS' request to change accounting for economic oil burns. We developed the one-company policy because it results in the most efficient use of resources. The fact that it is not applied across companies, like Southern California Edison and Southern California Gas, does not make it unfair. The

Commission, in D.87-05-046, directed that shortfalls should be distributed to the UEG class to promote efficient production of electricity and on grounds of equity.

TURN proposes elimination of this account on the grounds that it provides too much protection to the utility. If it is not eliminated, TURN proposes that undercollections be recovered from UEG and cogeneration customers.

SCE supports PG&E's proposal on the grounds that this "subsidy" to cogenerators is based on the presumed benefits of more efficient overall gas usage through the cogeneration process. Since those benefits accrue to all customers, all customers should pay the subsidy.

We will adopt DRA and CCC's recommendation to allocate shortfalls to the UEG class for the reasons we adopted this practice in D.87-05-046. In response to SCE's comments, we believe it more appropriate to price services based on cost in order to send appropriate signals regarding use rather than to allocate costs on the basis of incidental and widely dispersed benefits of a technology.

We will not eliminate this account at this time, as TURN suggests. However, we believe that as PG&E's competitive posture improves under our new regulatory program, it may be appropriate to eliminate this and similar accounts designed to protect the utility during this transition period.

b. Proposed Accounting Change to CSA

PG&E requests that the Commission approve a modification to the CSA. Under its proposal, PG&E would book the difference between revenues at the adopted average UEG rate and the average rate actually paid. Under existing practice, PG&E books the difference between cogeneration revenues at the actual UEG average rate and the otherwise applicable schedule, whenever the latter is lower.

converse--that cogenerators receive a windfall from a two-company policy--could also be true.

In addition, DGS' proposal would require us to reallocate revenues from cogenerators to other classes of customers, which we will not undertake in this ACAP. Finally, cogenerators may still opt to use the otherwise applicable industrial rate when UEG rates increase.

6. <u>Pipeline Demand Charges</u>

PG&E requests that the Commission allow balancing account treatment of pipeline demand charges. We turned down this request in D.87-12-039, stating that we would not adopt any further guarantees for the recovery of these costs. We will not reverse our policy on this issue. We will, however, adopt PG&E's forecast estimate of $174.8 million for this expense.

7. <u>Storage Inventory Carrying Costs</u>

PG&E requests balancing account treatment for storage inventory carrying costs associated with the noncore market. In G-2787, we adopted a balancing account for this cost, and will implement it in this order.

8. **Revenue Shortfalls Resulting <u>From Reassignment of Core Customers</u>**

In G-2796, we directed PG&E to track revenue shortfalls resulting from transferring core customers to noncore status. We stated we would determine treatment of those shortfalls in this proceeding.

TURN proposes that these revenue shortfalls be shared equally between ratepayers and shareholders. According to TURN, this would give the utility the incentive to adjust its cost allocations to capture the reassignment of such customers as quickly as possible. Once such customers are treated as noncore for cost allocation, there would no longer be any ongoing impact on the core balancing account. TURN adds that the shortfall from the Stone Container Corporation contract should be borne entirely by

PG&E argues that the current accounting method leads to a shortfall because of differences between forecasted revenues and actual revenues occurring due to weather. Under our rules, cogenerators may purchase gas out of either UEG tariffs or otherwise applicable rates. During a dry year, rates for the UEG class fall below those forecasted (because demand is higher and fixed costs are spread over larger volumes than expected). When UEG rates are lower than other rates applicable to cogenerators, those customers use the UEG rate, leading to a shortfall from them.

PG&E forecasts that it will lose about $5.0 million between May and December 1988 as a result of this effect. Accordingly, PG&E requests that the Commission "smooth the year-to-year effects of the adopted cost allocation and rate design policies on cogeneration gas transportation revenues" which occur because of weather. In the alternative, PG&E states forecasting QF gas prices would take care of the problem. This approach is being discussed between PG&E and QFs.

Other parties to the proceeding object to PG&E's proposal. TURN points out that during a dry year, PG&E may lose revenues from cogenerators, but its revenues from UEG customers increase. DRA objects to the proposal because the modification would reduce risk to PG&E and increase risk for its ratepayers. According to DRA, PG&E is already protected from underrecovery of noncore revenues by way of the NRSA account and that potential losses during some years would be offset during others. PG&E should not be granted increased regulatory protections six months after the new program has been put into place. CCC and DGS also oppose PG&E's proposal.

We will not adopt PG&E's proposal. We agree with DRA and TURN that the modification effectively shifts risk from PG&E to core customers. The risk PG&E currently bears for a cogeneration shortfall is not excessive and is offset by potential gains from UEG customers during a dry year. Further, the probability of

PG&E since the Commission rejected that contract in Resolution G-2818.

PG&E believes TURN's proposal is unfair and illogical. Since revenues received from reassigned customers continue to be recorded in core balancing accounts, there is no windfall for shareholders through the noncore gas fixed cost account. Core customers are actually better off as a result of reassignment than they would have been without it because they continue to receive some revenues rather than none.

While shared losses may provide some incentive for the utility to reduce costs, we agree with PG&E that the value of the incentive is outweighed by the issue of fairness. The existing accounting treatment for customers who have transferred to noncore status is reasonable and generally consistent with our program.

D. Rate Design

Generally, the parties applied the rate design principles established in D.87-12-039. They also applied the conceptual framework for baseline rates adopted in D.88-10-062. Our final rate design is presented in Appendix C.

1. Baseline Rates

PG&E proposes to set residential rates so that the 93.7% differential between tiers is consistent with that adopted in D.88-10-062. DRA generally agrees with this rate design proposal, but recommends retaining the $.40 per therm differential between Baseline and Tier II adopted in D.88-10-062. DRA notes that using PG&E's percentage difference will result in a rate spread of about $.44, an amount the Commission rejected in its baseline order.

We will adopt DRA's proposed $.40 per therm differential as reasonable and consistent with D.88-10-062 and SB 987.

2. Summer and Winter Commercial Rates

PG&E proposes a 35% differential between summer and winter commercial rates. According to PG&E, this differential was losses in some years is offset by the probability of gains in others.

We remind PG&E that our program was developed to provide improved incentives for efficiency for PG&E and additional opportunities to benefit from competition. Increased protections in gas markets will only be granted where significant harm would otherwise result to shareholders or ratepayers. Whether QF gas prices are based on a forecast is an issue which may be considered in other Commission proceedings and we need not address it here.

5. Oil Burn Credit for Cogenerators

DGS proposed a mechanism to address the effects of economic oil burns on cogeneration rates. Under current policy, PG&E switches from gas to oil whenever oil is cheaper than the incremental cost of gas (even though oil may be more expensive than the core WACOG). As throughput drops, cogeneration gas rates increase to reflect the higher UEG rates from two months previous.

DGS proposes that during months when economic oil burns occur, the cogeneration gas rate should be developed by dividing gas fixed costs by throughput including both gas and oil burned for economic reasons. According to DGS, such a mechanism would put cogenerators in the same position as they would be in if PG&E operated under a "two-company" policy. Under a two-company policy, PG&E would burn oil only when the oil price was less than the core-elect WACOG, resulting in fewer oil burns.

PG&E objects to DGS's proposal on the grounds that the Commission has recognized that the actual average rate paid by UEG customers (and therefore cogeneration customers) will vary monthly according to many factors, including weather conditions. DGS' proposal, according to PG&E, is one-sided and insulates cogenerators from one factor that can increase their rates. If UEG rates are higher than otherwise applicable rates, cogenerators may switch schedules.

adopted by the Commission in D.87-12-039, and in recognition that the actual winter/summer differential appeared to be more than 35%.

TURN characterizes this differential as "excessive," observing that PG&E apparently allocated all distribution related costs exclusively to the winter period. TURN argues that distribution facilities must be in place to serve load all year long. Accordingly, the differential in cost attributable to peak usage should be allocated as a winter-only cost component to avoid placing an undue burden on seasonal commercial customers.

DRA concurs with PG&E's method as reasonable and consistent with D.87-12-039. We will continue to use the practice adopted in that order.

3. Take-or-Pay and El Paso Direct Bill Balancing Account

DRA and DGS propose that the take-or-pay and El Paso direct bill balancing accounts should be collected volumetrically to encourage the utilities to negotiate the best rate with pipelines. We believe this is reasonable approach and will reflect it in our adopted rate design.

4. Transition Cost and Implementation Balancing Account Surcharges

PG&E proposes that it be permitted to discount Transition Cost and Implementation Balancing Account (TC/IBA) surcharges. PG&E believes this additional flexibility will allow it to retain load.

DRA and TURN support this proposal. DRA states that PG&E, if granted this flexibility, be required to (1) book negotiated revenue above variable and customers costs first, to implementation and transition accounts; and (2) apportion necessary discounts to all accounts pro rata so that its guarantee to eventually recover remaining balances can be scrutinized on an account-by-account basis. TURN supports DRA's recommendations. PG&E does not object to them.

SCE also objects to DGS' proposal. SCE states the distortion between cogenerator and UEG rates is not due to the "one-company" policy but rather due to distortions caused by PG&E's demand charges.

We will not grant DGS' request to change accounting for economic oil burns. We developed the one-company policy because it results in the most efficient use of resources. The fact that it is not applied across companies, like Southern California Edison and Southern California Gas, does not make it unfair. The converse--that cogenerators receive a windfall from a two-company policy--could also be true. Under existing policy, cogenerators may still opt to use the otherwise applicable industrial rate when UEG rates increase.

6. Revenue Shortfalls Resulting From Reassignment of Core Customers

In Resolution G-2796, we directed PG&E to track revenue shortfalls resulting from transferring core customers to noncore status. We stated we would determine treatment of those shortfalls in this proceeding.

TURN proposes that these revenue shortfalls be shared equally between ratepayers and shareholders. According to TURN, this would give the utility the incentive to adjust its cost allocations to capture the reassignment of such customers as quickly as possible. Once such customers are treated as noncore for cost allocation, there would no longer be any ongoing impact on the core balancing account. TURN adds that the shortfall from the Stone Container Corporation contract should be borne entirely by PG&E since the Commission rejected that contract in Resolution G-2818.

PG&E believes TURN's proposal is unfair and illogical. Since revenues received from reassigned customers continue to be recorded in core balancing accounts, there is no windfall for shareholders through the noncore gas fixed cost account. Core

We agree that the additional flexibility PG&E requests may reduce load loss. We will adopt DRA's suggestions regarding associated accounting principles.

E. <u>Revenue Requirement</u>

1. <u>Balancing Account Balances</u>

The parties agreed that we should use the latest available information regarding balancing accounts balances. On February 9, 1989, PG&E filed an update of balancing account amounts including the PGA as of January 31, 1989. The final amount is $205.2 million, which is to be amortized over one year with the exception of the core and noncore implementation balancing accounts, which are to be amortized over 16 months. The balances are presented in Appendix B, Table 6.

PG&E proposes to seasonally adjust the Core Gas Fixed Cost Account (GFCA) by forecasting undercollections as of April 1989 to mitigate a potentially large increase to core customers. DRA concurs with these proposals.

Both SCE and DGS recommend extending balancing account amortization periods if required to avoid rate shock. In addition, DGS believes the Commission should provide a 45-day period before implementing new rates in order to allow customers to respond in advance to increased rates. CIG proposes a grace period of four months. PG&E states there is no justification for this delay beyond the self-interest of the parties proposing it.

The only other controversy regarding balancing account amounts concerned the CFA. DRA challenged PG&E's estimate for the allowance for doubtful accounts, recommending a $3.6 million adjustment to the CFA. PG&E has agreed to the adjustment, and we have reflected this in the updated balancing account balances.

We will not adopt proposals by DGS and CIG to defer rate implementation. The effect of that would be to put further upward pressure on rates in the subsequent period. Additionally, large customers should be able to respond quickly enough to higher rates customers are actually better off as a result of reassignment than they would have been without it because they continue to receive some revenues rather than none.

While shared losses may provide some incentive for the utility to reduce costs, we agree with PG&E that the value of the incentive is outweighed by the issue of fairness. The existing accounting treatment for customers who have transferred to noncore status is reasonable and generally consistent with our program.

D. Rate Design

Generally, the parties applied the rate design principles established in D.87-12-039. They also applied the conceptual framework for baseline rates adopted in D.88-10-062. Our final rate design is presented in Appendix C.

1. Baseline Rates

PG&E proposes to set residential rates so that the 93.7% differential between tiers is consistent with that adopted in D.88-10-062. DRA generally agrees with this rate design proposal, but recommends retaining the $.40 per therm differential between Baseline and Tier II adopted in D.88-10-062. DRA notes that using PG&E's percentage difference will result in a rate spread of about $.44, an amount the Commission rejected in its baseline order.

We will adopt DRA's proposed $.40 per therm differential as reasonable and consistent with D.88-10-062 and SB 987.

2. Summer and Winter Commercial Rates

PG&E proposes a 35% differential between summer and winter commercial rates. According to PG&E, this differential was adopted by the Commission in D.87-12-039, and in recognition that the actual winter/summer differential appeared to be more than 35%.

TURN characterizes this differential as "excessive", observing that PG&E apparently allocated all distribution related costs exclusively to the winter period. TURN argues that distribution facilities must be in place to serve load all year long. Accordingly, the differential in cost attributable to peak if it serves their interests. Those customers have had an opportunity to plan for rate increases since September 1988 by way of PG&E's customer notice.

Since balancing account balance undercollections are not large, we will amortize them with the exception of CIBA and NIBA balances over a one-year period, which is our usual practice. CIBA and NIBA balances will be amortized over 16 months.

2. 1989 Attrition Year Revenue Requirement

PG&E requested that its base revenues in this filing be updated to reflect 1989 attrition year revenue requirement adopted in G-2838. The parties did not object. PG&E's gas revenue requirement for 1989 was increased $37.18 million by Commission Resolution G-2838. The total gas revenue requirement adopted in this proceeding is updated to reflect these attrition year adjustments.

3. Total Revenue Requirement

PG&E's modified 1989 ACAP application requests a total gas revenue requirement of $2,656.7 million, which does not reflect 1989 attrition changes or updated balancing account estimates. Our adopted revenue requirement based on the findings made above is $2,805.4 million and is presented in Appendix B, Table 6. This reflects the 1989 attrition changes and balancing account balances as of January 31, 1989.

F. Other Matters

1. Notice Requirements

TURN notes that PG&E's total revenue requirement increased substantially in its amended filing, but PG&E did not notify its customers of that increase. TURN states the Commission has consistently refused to grant a revenue requirement higher than that noticed to customers, and suggests that the Commission continue to follow that policy.

DRA agrees that PG&E should have amended its application and noticed that change. DRA notes that the exception to the rule usage should be allocated as a winter-only cost component to avoid placing an undue burden on seasonal commercial customers.

DRA concurs with PG&E's method as reasonable and consistent with D.87-12-039. We will continue to use the practice adopted in that order.

3. Take-or-Pay and El Paso Direct Bill Balancing Account

DRA and DGS propose that existing take-or-pay costs should be collected volumetrically to encourage the utilities to negotiate the best rate with pipelines. We believe this is reasonable approach and will reflect it in our adopted rate design. Existing direct bill expenses should continue to be recovered in the demand charge, pursuant to D.87-12-039.

4. Transition Cost and Implementation Balancing Account Surcharges

PG&E proposes that it be permitted to discount Transition Cost and Implementation Balancing Account (TC/IBA) surcharges. PG&E believes this additional flexibility will allow it to retain load.

DRA and TURN support this proposal. DRA states that PG&E, if granted this flexibility, be required to (1) book negotiated revenue above variable and customers costs first, to implementation and transition accounts; and (2) apportion necessary discounts to all accounts pro rata so that its guarantee to eventually recover remaining balances can be scrutinized on an account-by-account basis. TURN supports DRA's recommendations. PG&E does not object to them.

We agree that the additional flexibility PG&E requests may reduce load loss. We will adopt DRA's suggestions regarding associated accounting principles.

is a case where increase in expenses results from updated balancing account balances. In this case, forecast assumptions--not balancing account expenses--changed.

PG&E responds that its notice includes reference to the fact that the rates adopted by the Commission may be higher or lower than those requested.

In this case, we do not need to rule on the notice issue since we authorize a revenue requirement increase for PG&E less than the amount shown in its original notice. We have, in this order, directed PG&E to refrain from late-filed changes to its application in future proceedings except in unusual cases. If it does increase its rate request following the original notice, we will at that time consider whether additional notice is required.

2. Proprietary Information

A number of parties objected to PG&E's use of proprietary data in this proceeding. DGS suggested that PG&E's refusal to disclose information used as inputs to its models was "arrogant" and future proceedings should not permit use of "black box" ratemaking.

TURN suggests that PG&E should be required to include in its workpapers complete documentation of any computer models used in preparing the company's case, consistent with AB 475 and in order to preclude the time-consuming process of discovery which arose in this case. TURN also criticizes PG&E's use of a confidential assessment of willingness-to-pay. The confidentiality of this information, according to TURN, has lead to discovery problems in this proceeding. Finally, TURN also states that relying upon PG&E to run the model--because Commission staff cannot run the model independently--is cumbersome and creates the appearance of impropriety. DRA generally supports TURN's comments.

We are currently considering general rules regarding access to computer models in I.88-04-030. These rules will address access to models in future ACAPs.

E. <u>Revenue Requirement</u>

1. <u>Balancing Account Balances</u>

The parties agreed that we should use the latest available information regarding balancing accounts balances. On February 9, 1989, PG&E filed an update of balancing account amounts including the PGA as of January 31, 1989. The final amount is $205.2 million, which is to be amortized over one year with the exception of the core and noncore implementation balancing accounts, which are to be amortized over 16 months. The balances are presented in Appendix B, Table 6.

PG&E proposes to seasonally adjust the Core Gas Fixed Cost Account (GFCA) by forecasting undercollections as of April 1989 to mitigate a potentially large increase to core customers. DRA concurs with these proposals.

Both SCE and DGS recommend extending balancing account amortization periods if required to avoid rate shock. In addition, DGS believes the Commission should provide a 45-day period before implementing new rates in order to allow customers to respond in advance to increased rates. CIG proposes a grace period of four months. PG&E states there is no justification for this delay beyond the self-interest of the parties proposing it.

The only other controversy regarding balancing account amounts concerned the CFA. DRA challenged PG&E's estimate for the allowance for doubtful accounts, recommending a $3.6 million adjustment to the CFA. PG&E has agreed to the adjustment, and we have reflected this in the updated balancing account balances.

We will not adopt proposals by DGS and CIG to defer rate implementation. The effect of that would be to put further upward pressure on rates in the subsequent period. Additionally, large customers should be able to respond quickly enough to higher rates if it serves their interests. Those customers have had an opportunity to plan for rate increases since September 1988 by way of PG&E's customer notice.

3. Updated Information

The parties generally agree that the most recent balancing account balances should be reflected in the Commission's final order. PG&E had also requested an opportunity to update forecast information. During hearings, a number of parties objected to this updating. DRA points out that updating contested issues after the conclusion of hearings would make the hearing process meaningless. We agree with that assessment and will not entertain updates of contested issues in future ACAPs.

IV. Conclusions

This first ACAP has been a complex and contentious proceeding. The controversy is due, in part, to the fact that PG&E is now at greater risk for revenue recovery, making the forecasting stakes higher. PG&E's application in this proceeding paints a bleak picture of the future. It forecasts significant and in some cases dramatic increases for all classes of customers.

In addition, forecasting by its nature can be extremely complex. In this case, PG&E used two complicated models which were made more complex by their interaction. This decision seeks to minimize model complexities and simplify specifications and assumptions that do not detract from the model's usefulness.

The complexity and controversy were increased when PG&E made significant changes to its application during the hearing process. The introduction of these changes required additional efforts by the parties to review the data, and additional hearing days.

A major objective of this decision is to establish a framework for analyzing throughput in future ACAPs. It cannot resolve all forecasting problems. We believe forecasts will improve as the utilities, the parties, and the Commission gain experience with the ACAP process and with the evolving gas markets.

Since balancing account balance undercollections are not large, we will amortize them with the exception of CIBA and NIBA balances over a one-year period, which is our usual practice. CIBA and NIBA balances will be amortized over 16 months.

2. 1989 Attrition Year Revenue Requirement

PG&E requested that its base revenues in this filing be updated to reflect 1989 attrition year revenue requirement adopted in G-2838. The parties did not object. PG&E's gas revenue requirement for 1989 was increased $37.18 million by Commission Resolution G-2838. The total gas revenue requirement adopted in this proceeding is updated to reflect these attrition year adjustments.

3. Total Revenue Requirement

PG&E's modified 1989 ACAP application requests a total gas revenue requirement of $2,656.7 million, which does not reflect 1989 attrition changes or updated balancing account estimates. Our adopted revenue requirement based on the findings made above is $_______ million and is presented in Appendix B, Table 6. This reflects the 1989 attrition changes and balancing account balances as of January 31, 1989.

F. Other Matters

1. Notice Requirements

TURN notes that PG&E's total revenue requirement increased substantially in its amended filing, but PG&E did not notify its customers of that increase. TURN states the Commission has consistently refused to grant a revenue requirement higher than that noticed to customers, and suggests that the Commission continue to follow that policy.

DRA agrees that PG&E should have amended its application and noticed that change. DRA notes that the exception to the rule is a case where increase in expenses results from updated balancing account balances. In this case, forecast assumptions--not balancing account expenses--changed.

Since balancing account balance undercollections are not large, we will amortize them with the exception of CIBA and NIBA balances over a one-year period, which is our usual practice. CIBA and NIBA balances will be amortized over 16 months.

2. 1989 Attrition Year Revenue Requirement

PG&E requested that its base revenues in this filing be updated to reflect 1989 attrition year revenue requirement adopted in G-2838. The parties did not object. PG&E's gas revenue requirement for 1989 was increased $37.18 million by Commission Resolution G-2838. The total gas revenue requirement adopted in this proceeding is updated to reflect these attrition year adjustments.

3. Total Revenue Requirement

PG&E's modified 1989 ACAP application requests a total gas revenue requirement of $2,656.7 million, which does not reflect 1989 attrition changes or updated balancing account estimates. Our adopted revenue requirement based on the findings made above is $2,821.2 million and is presented in Appendix B, Table 6. This reflects the 1989 attrition changes and balancing account balances as of January 31, 1989.

F. Other Matters

1. Notice Requirements

TURN notes that PG&E's total revenue requirement increased substantially in its amended filing, but PG&E did not notify its customers of that increase. TURN states the Commission has consistently refused to grant a revenue requirement higher than that noticed to customers, and suggests that the Commission continue to follow that policy.

DRA agrees that PG&E should have amended its application and noticed that change. DRA notes that the exception to the rule is a case where increase in expenses results from updated balancing account balances. In this case, forecast assumptions--not balancing account expenses--changed.

While we anticipate improvements to forecasts, we intend that the guidance provided by this order be applied in the future.

We also comment on other aspects of future ACAPs. It is our intent, as time goes on, to modify our program to provide the utilities with more opportunities to compete, and thereby further encourage efficiency in gas markets. Accordingly, we do not anticipate increasing regulatory protections for PG&E, as it has requested in this proceeding, but rather reducing them, barring changes which make gas markets less competitive. Accordingly, we expect to review the viability of balancing accounts and other protective mechanisms which may be better transitional practices than permanent ones. We also intend to look further at our cost allocation practices which affect the competitiveness of the market and of the utilities.

Throughout, we retain our commitment to protecting the core from unnecessary rate increases and service problems. In effect, we continue to recognize that core customers are best protected in competitive markets when rates are set closer to cost, thereby preventing uneconomic bypass of utility networks. We also believe that competition, if successful, will work to reduce the cost of gas for all customers.

Findings of Fact

1. Gas throughput is the total demand for natural gas from the utility system, including sales and transport gas.

2. PG&E's estimate of gas throughput included the use of econometric models to forecast the effects of economic activity, fuel prices, weather and other factors on demand.

3. PG&E used a discount adjustment model to forecast discounts from tariffed transport rates required to keep large customers from P2B, G-IND, and COGEN on its system.

4. DRA's assumption that a recession will not occur in 1989 is supported by industry analysts.

PG&E responds that its notice includes reference to the fact that the rates adopted by the Commission may be higher or lower than those requested.

In this case, we do not need to rule on the notice issue since we authorize a revenue requirement increase for PG&E less than the amount shown in its original notice. We have, in this order, directed PG&E to refrain from late-filed changes to its application in future proceedings except in unusual cases. If it does increase its rate request following the original notice, we will at that time consider whether additional notice is required.

2. Proprietary Information

A number of parties objected to PG&E's use of proprietary data in this proceeding. DGS suggested that PG&E's refusal to disclose information used as inputs to its models was "arrogant" and future proceedings should not permit use of "black box" ratemaking.

TURN suggests that PG&E should be required to include in its workpapers complete documentation of any computer models used in preparing the company's case, consistent with AB 475 and in order to preclude the time-consuming process of discovery which arose in this case. TURN also criticizes PG&E's use of a confidential assessment of willingness-to-pay. The confidentiality of this information, according to TURN, has lead to discovery problems in this proceeding. Finally, TURN also states that relying upon PG&E to run the model--because Commission staff cannot run the model independently--is cumbersome and creates the appearance of impropriety. DRA generally supports TURN's comments.

We are currently considering general rules regarding access to computer models in I.88-04-030. These rules will address access to models in future ACAPs.

3. Updated Information

The parties generally agree that the most recent balancing account balances should be reflected in the Commission's

5. Some of PG&E's customers purchase propane at retail rates.

6. Forecasted propane prices during the test period should include weighted values for the cost of retail and wholesale propane prices according to the percentage of customers who purchase propane at retail and wholesale rates.

7. Fuel oil prices declined during the final months of 1988, prior to OPEC price-setting meetings.

8. PG&E's estimates of customer growth during the test period are reasonable.

9. Models used to forecast required discounts for PG&E's noncore customers should include an estimate of the effects of demand charges on customer decisions to fuel switch.

10. PG&E did not provide evidence that customer perceptions regarding service reliability have changed since D.87-12-039 was issued.

11. GC-2 customers are not distinguished from other customers in terms of the value of gas relative to the value of alternative fuels.

12. Significant numbers of PG&E's large noncore customers may elect core status. A model designed to estimate required discounts for noncore customers would provide a more accurate estimate of noncore revenue if it included core and noncore gas prices, weighted according to volumes purchased.

13. Cogeneration purchases used to generate steam are appropriately included in industrial throughput estimates.

14. Cogeneration purchases sold under the G-IND tariff are appropriately included in industrial throughput estimates.

15. PG&E appropriately estimates UEG volumes based on average hydro year conditions.

16. Estimates of UEG volumes should be based on estimates and methodologies adopted in PG&E's and SCE's ECAC proceedings, to the extent those estimates are based on average hydro year conditions.

final order. PG&E had also requested an opportunity to update forecast information. During hearings, a number of parties objected to this updating. DRA points out that updating contested issues after the conclusion of hearings would make the hearing process meaningless. We agree with that assessment and will not entertain updates of contested issues in future ACAPs.

IV. Conclusions

This first ACAP has been a complex and contentious proceeding. The controversy is due, in part, to the fact that PG&E is now at greater risk for revenue recovery, making the forecasting stakes higher. PG&E's application in this proceeding paints a bleak picture of the future. It forecasts significant and in some cases dramatic increases for all classes of customers.

In addition, forecasting by its nature can be extremely complex. In this case, PG&E used two complicated models which were made more complex by their interaction. This decision seeks to minimize model complexities and simplify specifications and assumptions that do not detract from the model's usefulness.

The complexity and controversy were increased when PG&E made significant changes to its application during the hearing process. The introduction of these changes required additional efforts by the parties to review the data, and additional hearing days.

A major objective of this decision is to establish a framework for analyzing throughput in future ACAPs. It cannot resolve all forecasting problems. We believe forecasts will improve as the utilities, the parties, and the Commission gain experience with the ACAP process and with the evolving gas markets. While we anticipate improvements to forecasts, we intend that the guidance provided by this order be applied in the future.

17. PG&E's and DRA's estimates of residential and commercial throughput for the test period are almost identical.

18. TURN's proposed methodology for estimating required noncore volume discounts is more accessible and understandable than PG&E's.

19. TURN's proposed model is a reasonable alternative to PG&E's discount adjustment model for purposes of forecasting required discounts to noncore customers.

20. Workshops are likely to help interested parties understand ACAP forecasting models and will provide a forum for determining improvements to forecasting methods.

21. Changes in oil prices influence, to some extent, gas prices. Estimates of gas prices during the test period which reflect this relationship are likely to be more accurate than those which do not.

22. No clear historic relationship between gas and oil prices is apparent.

23. The noncore portfolio contains short-term supplies with prices that are firm for up to thirty days.

24. The core portfolio contains all long-term supplies and any short-term supplies needed to meet demand.

25. El Paso supplies are likely to be too expensive to be purchased economically during the test period.

26. PG&E has stipulated, in PGT's general rate case, to an estimate of 1,009 MMcf/day over the PGT pipeline. PG&E transported, on average, 1,009 MMcf/day over the PGT pipeline between January 1988 and November 1988.

27. A deferred debit account will reduce PG&E's risk of recovering costs related to pending El Paso filings at the FERC.

28. Allocating NRSA balances on an equal-cents-per-therm basis reasonably approximates the cost allocation which would have occurred if cost and revenue forecasts had been accurate.

We also comment on other aspects of future ACAPs. It is our intent, as time goes on, to modify our program to provide the utilities with more opportunities to compete, and thereby further encourage efficiency in gas markets. Accordingly, we do not anticipate increasing regulatory protections for PG&E, as it has requested in this proceeding, but rather reducing them, barring changes which make gas markets less competitive. Accordingly, we expect to review the viability of balancing accounts and other protective mechanisms which may be better transitional practices than permanent ones. We also intend to look further at our cost allocation practices which affect the competitiveness of the market and of the utilities, consistent with the requirements of SB 987.

Throughout, we retain our commitment to protecting the core from unnecessary rate increases and service problems. In effect, we continue to recognize that core customers are best protected in competitive markets when rates are set closer to cost, thereby preventing uneconomic bypass of utility networks. We also believe that competition, if successful, will work to reduce the cost of gas for all customers.

<u>Findings of Fact</u>

1. Gas throughput is the total demand for natural gas from the utility system, including sales and transport gas.

2. PG&E's estimate of gas throughput included the use of econometric models to forecast the effects of economic activity, fuel prices, weather and other factors on demand.

3. PG&E used a discount adjustment model to forecast discounts from tariffed transport rates required to keep large customers from P2B, G-IND, and COGEN on its system.

4. DRA's assumption that a recession will not occur in 1989 is supported by industry analysts.

5. Some of PG&E's customers purchase propane at retail rates.

29. Allocating CSA undercollections to the UEG class promotes efficiency and equity.

30. PG&E may realize a revenue shortfall from cogenerators during dry years when the UEG rate falls below the otherwise applicable rate to cogenerators.

31. The risk PG&E bears for a cogeneration shortfall under existing CSA accounting practices is offset by potential gains from UEG customers during a dry year, and by potential gains under the CSA during a wet year.

32. Changing CSA accounting practices at this time would provide unwarranted regulatory protections to PG&E.

33. PG&E's UEG facility switches from gas to oil whenever oil is cheaper than the incremental cost of gas. As UEG throughput falls, cogeneration gas rates increase to pick up fixed costs allocated to UEG and cogeneration customers.

34. PG&E's "one-company policy" is designed to promote efficient use of resources.

35. Determining the cogeneration gas rate by dividing gas fixed costs by throughput, including both gas and oil burned for economic reasons, would require a reallocation of revenues from cogenerators to other classes of customers.

36. Cogenerators may opt to use the otherwise applicable gas rate when UEG rates increase.

37. This proceeding did not anticipate addressing whether SCE's Cool Water plant should be treated as a UEG facility.

38. Balancing account treatment for pipeline demand charges would provide an unwarranted revenue recovery guarantee to PG&E.

39. PG&E may be able to retain additional load by discounting transition cost and implementation balancing account amounts.

40. Booking negotiated transportation revenues in excess of variable and customer related costs to TC/IBA accounts will provide appropriate safeguards in cases where PG&E discounts TC/IBA surcharges.

6. Forecasted propane prices during the test period should include weighted values for the cost of retail and wholesale propane prices according to the percentage of customers who purchase propane at retail and wholesale rates.

7. Fuel oil prices declined during the final months of 1988, prior to OPEC price-setting meetings, but have since increased.

8. PG&E's estimates of customer growth during the test period are reasonable.

9. Models used to forecast required unadjusted throughput and discounts for PG&E's noncore customers should include an estimate of the effects of demand charges on customer decisions to fuel switch.

10. PG&E did not provide evidence that customer perceptions regarding service reliability have changed since D.87-12-039 was issued.

11. GC-2 customers with contracts that expire in 1989 are not distinguished from other customers in terms of the value of gas relative to the value of alternative fuels, once those contracts expire.

12. Significant numbers of PG&E's large noncore customers may elect core status. A model designed to estimate required discounts for noncore customers would provide a more accurate estimate of noncore revenue if it included core and noncore gas prices, weighted according to volumes purchased.

13. Cogeneration purchases used to generate steam are appropriately included in industrial throughput estimates.

14. Cogeneration purchases sold under the G-IND tariff are appropriately included in industrial throughput estimates.

15. PG&E appropriately estimates UEG volumes based on average hydro year conditions.

16. Estimates of UEG volumes should be based on estimates and methodologies adopted in PG&E's and SCE's ECAC proceedings, to the extent those estimates are based on average hydro year conditions.

41. Collecting take-or-pay and El Paso direct bill balancing account amounts volumetrically will provide the utilities improved incentives to negotiate the best rates with pipelines.

42. Deferring rate implementation will place upward pressure on rates in subsequent periods.

43. Escalating EOR and GC-2 revenues according to contracted amounts provides a more accurate forecast of those revenues.

44. Updating contested information following hearings fails to permit appropriate review of such information.

Conclusions of Law

1. PG&E should be authorized to make tariff changes in accordance with the rates shown in Appendix C.

2. CACD should schedule workshops to consider ACAP forecasting models and explore refinements to them.

3. The Commission should continue to use a 2% gas premium. The premium should apply to all noncore customers, including GC-2 customers.

4. Estimates of customer discounts should reflect customers' ability to elect core status, and should weight core and noncore gas prices according to volumes purchased.

5. PG&E's request to change CSA accounting practices should not be adopted.

6. DGS' request to change the way cogeneration rates are calculated during UEG oil burn periods should not be adopted.

7. Using the Lundberg survey, a reasonable estimate of propane prices for 1989 is $0.314 per therm.

8. A reasonable estimate of No. 6 fuel oil prices in 1989 is $16 per barrel, equivalent to $.268 per therm.

9. A reasonable estimate of No. 2 fuel oil for 1989 is the equivalent of $.352 per therm.

10. Models used to estimate PG&E's noncore volume discounts should include a proxy of demand charges in the amounts of $.03 per

17. PG&E's and DRA's estimates of residential and commercial throughput for the test period are almost identical.

18. TURN's proposed methodology for estimating required noncore volume discounts is more accessible and understandable than PG&E's.

19. TURN's proposed model is a reasonable alternative to PG&E's discount adjustment model for purposes of forecasting required discounts to noncore customers.

20. Workshops are likely to help interested parties understand ACAP forecasting models and will provide a forum for determining improvements to forecasting methods.

21. Changes in oil prices influence, to some extent, gas prices. Estimates of gas prices during the test period which reflect this relationship are likely to be more accurate than those which do not.

22. The noncore portfolio contains short-term supplies with prices that are firm for up to thirty days.

23. The core portfolio contains all long-term supplies and any short-term supplies needed to meet demand.

24. El Paso supplies are likely to be too expensive to be purchased economically during the test period.

25. PG&E has stipulated, in PGT's general rate case, to an estimate of 1,009 MMcf/day over the PGT pipeline. PG&E transported, on average, 1,009 MMcf/day over the PGT pipeline between January 1988 and November 1988.

26. A deferred debit account will reduce PG&E's risk of recovering costs related to pending El Paso filings at the FERC.

27. Allocating NRSA balances entirely to noncore rates is fair since core fixed costs are allocated entirely to the core, and because such allocation does not result in changes to established allocation principles.

28. Allocating CSA undercollections to the UEG class promotes efficiency and equity.

therm for volumes associated with negotiated contracts and \$.05 per therm for volumes associated with default agreements.

11. A reasonable estimate of EOR throughput for the test period is 373 MMth.

12. A reasonable estimate of interutility throughput for the test period is 673 MMth.

13. A reasonable estimate of California gas prices during the test period is \$1.80 per MMBtu.

14. A reasonable estimate of Rocky Mountain gas prices for the test period is \$1.67 per MMBtu.

15. The currently effective price for Canadian gas supplies is \$1.847 per MMBtu at the California border and is a reasonable price estimate for the test period.

16. A reasonable estimate of Southwest gas prices for the test period is \$2.10 per MMBtu.

17. An estimate of 1,009 MMcf/day over the PGT line during the test period is reasonable.

18. A reasonable estimate of the core WACOG during the test period is \$1.886 per MMBtu.

19. A reasonable estimate of the noncore WACOG during the test period is \$1.90 per MMBtu.

20. It is reasonable to estimate storage-related transition costs based on an annual forecast.

21. It is reasonable to allocate PGA balances on an equal-cents-per-therm basis to core and core elect customers.

22. It is reasonable to allocate transition costs on an equal-cents-per-therm basis, with storage-related transition costs allocated using a cold year forecast.

23. It is reasonable to allocate EOR revenue credits on DRA's methodology of an equal percentage of fixed costs.

24. It is reasonable to permit balancing account treatment for storage inventory carrying costs, consistent with G-2787.

29. PG&E may realize a revenue shortfall from cogenerators during dry years when the UEG rate falls below the otherwise applicable rate to cogenerators.

30. The risk PG&E bears for a cogeneration shortfall under existing CSA accounting practices is offset by potential gains from UEG customers during a dry year, and by potential gains under the CSA during a wet year.

31. Changing CSA accounting practices at this time would provide unwarranted regulatory protections to PG&E.

32. PG&E's UEG facility switches from gas to oil whenever oil is cheaper than the incremental cost of gas. As UEG throughput falls, cogeneration gas rates increase because the fixed UEG demand charge is spread over smaller volumes in the rate parity formula.

33. PG&E's "one-company policy" is designed to promote efficient use of resources.

34. Cogenerators may opt to use the otherwise applicable gas rate when UEG rates increase.

35. This proceeding did not anticipate addressing whether SCE's Cool Water plant should be treated as a UEG facility.

36. PG&E may be able to retain additional load by discounting transition cost and implementation balancing account amounts.

37. Booking negotiated transportation revenues in excess of variable and customer related costs to TC/IBA accounts will provide appropriate safeguards in cases where PG&E discounts TC/IBA surcharges.

38. Collecting take-or-pay transition costs volumetrically will provide the utilities improved incentives to negotiate the best rates with pipelines.

39. Deferring rate implementation will place upward pressure on rates in subsequent periods.

40. Escalating EOR and GC-2 revenues according to contracted amounts provides a more accurate forecast of those revenues.

25. The existing accounting treatment of revenues from reassignment of core customers is reasonable.

26. It is reasonable to retain the $.40 per therm differential between baseline and Tier II rates.

27. A 35% differential between summer and winter commercial rates is reasonable.

28. It is reasonable to use most recent information regarding balancing account undercollections and overcollections in determining revenue requirement in this proceeding.

29. It is reasonable to adjust the Conservation Financing Account by $3.6 million to more accurately reflect the status of doubtful accounts.

30. It is reasonable to update base revenues to reflect the 1989 attrition year revenue requirement, adopted in Resolution G-2838.

31. A reasonable forecast of EOR credits is $6.9 million, adjusted for escalation using an escalation factor of 6.1% to produce an EOR revenue credit of $7.293 million.

32. A reasonable escalation factor for GC-2 credits is 3.738%.

O R D E R

IT IS ORDERED that,

1. Pacific Gas and Electric Company is authorized to file tariff changes which implement the rate changes adopted in this proceeding, and which are shown in Appendix C, using the revenue requirement presented in Appendix B, Table 6. Tariff changes will be effective 5 days after filing.

41. Updating contested information following hearings fails to permit appropriate review of such information.

Conclusions of Law

1. PG&E should be ordered to make tariff changes in accordance with the rates shown in Appendix C.

2. CACD should schedule workshops, following PG&E's next ACAP filing, to consider ACAP forecasting models and explore refinements to them.

3. The Commission should continue to use a $.02 gas premium. The premium should apply to all noncore customers, including GC-2 customers.

4. Estimates of customer discounts should reflect customers' ability to elect core status, and should weight core and noncore gas prices according to volumes purchased.

5. PG&E's request to change CSA accounting practices should not be adopted.

6. DGS' request to change the way cogeneration rates are calculated during UEG oil burn periods should not be adopted.

7. Using the Lundberg survey, a reasonable estimate of propane prices for 1989 is $0.361 per therm.

8. A reasonable estimate of No. 6 fuel oil prices in 1989 is $17 per barrel, equivalent to a $.285 delivered price and $.254 burnertip price.

9. A reasonable estimate of No. 2 fuel oil for 1989 is the equivalent of $.324 per therm.

10. Models used to estimate PG&E's unadjusted noncore throughput volume and rate discounts should include a proxy of demand charges in the amounts of $.03 per therm for volumes associated with negotiated contracts and $.05 per therm for volumes associated with default agreements.

11. A reasonable estimate of EOR throughput for the test period is 275 MMth.

41. Updating contested information following hearings fails to permit appropriate review of such information.

<u>Conclusions of Law</u>

1. PG&E should be ordered to make tariff changes in accordance with the rates shown in Appendix C.

2. CACD should schedule workshops, following PG&E's next ACAP filing, to consider ACAP forecasting models and explore refinements to them.

3. The Commission should continue to use a $.02 gas premium. The premium should apply to all noncore customers, including GC-2 customers.

4. Estimates of customer discounts should reflect customers' ability to elect core status, and should weight core and noncore gas prices according to volumes purchased.

5. PG&E's request to change CSA accounting practices should not be adopted.

6. DGS' request to change the way cogeneration rates are calculated during UEG oil burn periods should not be adopted.

7. Using the Lundberg survey, a reasonable estimate of propane prices for 1989 is $0.361 per therm.

8. A reasonable estimate of No. 6 fuel oil prices in 1989 is $17 per barrel, equivalent to a $.285 delivered price and $.254 burnertip price.

9. A reasonable estimate of No. 2 fuel oil for 1989 is the equivalent of $.324 per therm.

10. Models used to estimate PG&E's unadjusted noncore throughput volume and rate discounts should include a proxy of demand charges in the amounts of $.03 per therm for volumes associated with negotiated contracts and $.05 per therm for volumes associated with default agreements.

11. A reasonable estimate of EOR throughput for the test period is 373 MMth.

2. The Executive Director shall direct the Commission Advisory and Compliance Division to schedule workshops within 60 days. The purpose of the workshops will be to help interested parties to understand the models adopted in this proceeding and to explore improvements to models to be used in future ACAP proceedings.

This order is effective today.

Dated ____________________, at San Francisco, California.

12. A reasonable estimate of interutility throughput for the test period is 673 MMth.

13. A reasonable estimate of California gas prices during the test period is $1.85 per MMBtu.

14. A reasonable estimate of Rocky Mountain gas prices for the test period is $1.67 per MMBtu.

15. The currently effective price for Canadian gas supplies is $1.94 per MMBtu at the California border and is a reasonable price estimate for the test period.

16. A reasonable estimate of Southwest gas prices for the test period is $2.10 per MMBtu.

17. An estimate of 1,009 MMcf/day over the PGT line during the test period is reasonable.

18. A reasonable estimate of the core WACOG during the test period is $_____ per MMBtu.

19. A reasonable estimate of the noncore WACOG during the test period is $____ per MMBtu.

20. It is reasonable to estimate storage-related transition costs based on an annual forecast.

21. It is reasonable to allocate PGA balances on an equal-cents-per-therm basis to core and core elect customers.

22. It is reasonable to allocate existing transition costs on an equal-cents-per-therm basis, with storage-related transition costs allocated using a cold year forecast.

23. It is reasonable to allocate EOR revenue credits on DRA's methodology of an equal percentage of fixed costs.

24. The existing accounting treatment of revenues from reassignment of core customers is reasonable.

25. It is reasonable to retain the $.40 per therm differential between baseline and Tier II rates.

26. A 35% differential between summer and winter commercial rates is reasonable.

27. It is reasonable to use most recent information regarding balancing account undercollections and overcollections in determining revenue requirement in this proceeding.

28. It is reasonable to adjust the Conservation Financing Account by $3.6 million to more accurately reflect the status of doubtful accounts.

29. It is reasonable to update base revenues to reflect the 1989 attrition year revenue requirement, adopted in Resolution G-2838.

30. A reasonable forecast of EOR credits is $6.9 million, adjusted for escalation using an escalation factor of 6.1% to produce an EOR revenue credit of $7.293 million.

31. A reasonable escalation factor for GC-2 revenues is 3.738%.

ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) shall file, in accordance with General Order 96-A, tariff changes which implement the rate changes adopted in this proceeding, and which are shown in Appendix C, using the revenue requirement presented in Appendix B, Table 6. Tariff changes will be effective May 1, 1989.

12. A reasonable estimate of interutility throughput for the test period is 673 MMth.

13. A reasonable estimate of California gas prices during the test period is $1.85 per MMBtu.

14. A reasonable estimate of Rocky Mountain gas prices for the test period is $1.67 per MMBtu.

15. The currently effective price for Canadian gas supplies is $1.94 per MMBtu at the California border and is a reasonable price estimate for the test period.

16. A reasonable estimate of Southwest gas prices for the test period is $2.10 per MMBtu.

17. An estimate of 1,009 MMcf/day over the PGT line during the test period is reasonable.

18. A reasonable estimate of the core WACOG during the test period is $1.944 per MMBtu.

19. A reasonable estimate of the noncore WACOG during the test period is $1.90 per MMBtu.

20. It is reasonable to estimate storage-related transition costs based on an annual forecast.

21. It is reasonable to allocate PGA balances on an equal-cents-per-therm basis to core and core elect customers.

22. It is reasonable to allocate existing transition costs on an equal-cents-per-therm basis, with storage-related transition costs allocated using a cold year forecast.

23. It is reasonable to allocate EOR revenue credits on DRA's methodology of an equal percentage of fixed costs.

24. The existing accounting treatment of revenues from reassignment of core customers is reasonable.

25. It is reasonable to retain the $.40 per therm differential between baseline and Tier II rates.

26. A 35% differential between summer and winter commercial rates is reasonable.

27. It is reasonable to use most recent information regarding balancing account undercollections and overcollections in determining revenue requirement in this proceeding.

28. It is reasonable to adjust the Conservation Financing Account by $3.6 million to more accurately reflect the status of doubtful accounts.

29. It is reasonable to update base revenues to reflect the 1989 attrition year revenue requirement, adopted in Resolution G-2838.

30. A reasonable forecast of EOR credits is $6.9 million, adjusted for escalation using an escalation factor of 3.4% to produce an EOR revenue credit of $7.293 million.

31. A reasonable escalation factor for GC-2 revenues is 3.738%.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) shall file, in accordance with General Order 96-A, tariff changes which implement the rate changes adopted in this proceeding, and which are shown in Appendix C, using the revenue requirement presented in Appendix B, Table 6. Tariff changes will be effective May 1, 1989.

27. It is reasonable to use most recent information regarding balancing account undercollections and overcollections in determining revenue requirement in this proceeding.

28. It is reasonable to adjust the Conservation Financing Account by $3.6 million to more accurately reflect the status of doubtful accounts.

29. It is reasonable to update base revenues to reflect the 1989 attrition year revenue requirement, adopted in Resolution G-2838.

30. A reasonable forecast of EOR credits is $6.9 million, adjusted for escalation using an escalation factor of 3.4% to produce an EOR revenue credit of $7.293 million.

31. A reasonable escalation factor for GC-2 revenues is 3.738%.

ORDER

IT IS ORDERED that:

1. Within five (5) days of the effective date of this decision, Pacific Gas and Electric Company (PG&E) shall file, in accordance with General Order 96-A, tariff changes which implement the rate changes adopted in this proceeding, and which are shown in Appendix C to this decision, using the revenue requirement presented in Appendix B, Table 6. Tariff changes will be effective on the date of filing.

APPENDIX B

TABLE 1B

PACIFIC GAS AND ELECTRIC COMPANY

ANNUAL COST ALLOCATION PROCEEDING

ADOPTED DISCOUNT ADJUSTMENT MODEL FOR P2B

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	#2 OIL	#6 OIL	PROPANE	
Alternate Fuel Price (cents/therm)	35.2	26.8	31.4	
Gas Premium (cents/therm)	2.0	2.0	2.0	
Exit Demand Charges (cents/therm)	4.4	4.4	4.4	1/
Less: Average Cost of Gas (cents/therm)	19.7	19.7	19.7	2/
Maximum Transportation Rate (cents/therm)	21.9	13.5	18.1	3/
Seed Default Rate (cents/therm)	16.5	16.5	16.5	
Percent Discount Required	0.0%	18.1%	0.0%	4/
Unadjusted Volume Forecast (MDth)	448	1,791	5,373	
Discount Adjustment Volume (MDth)	0	325	0	5/

FOOTNOTES:

1/ ((ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT)) * 3 CENTS) + ((1 - (ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT))) * 5 CENTS)

2/ (55% * CORE PORTFOLIO PRICE) + (45% * NONCORE PORTFOLIO PRICE)

3/ ALTERNATE FUEL PRICE + GAS PREMIUM + EXIT DEMAND CHARGES - AVERAGE COST OF GAS

4/ (SEED DEFAULT RATE - MAXIMUM TRANSPORTATION RATE) / SEED DEFAULT RATE

5/ PERCENT DISCOUNT REQUIRED * UNADJUSTED VOLUME FORECAST

APPENDIX B

TABLE 1A
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED DISCOUNT ADJUSTMENT MODEL FOR G-IND

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	#2 OIL	#6 OIL	PROPANE	
Alternate Fuel Price (cents/therm)	37.4	28.5	36.1	
Gas Premium (cents/therm)	2.0	2.0	2.0	
Exit Demand Charges (cents/therm)	4.4	4.4	4.4	1/
Less: Average Cost of Gas (cents/therm)	20.0	20.0	20.0	2/
Maximum Transportation Rate (cents/therm)	23.8	14.9	22.5	3/
Seed Default Rate (cents/therm)	14.9	14.9	14.9	
Percent Discount Required	0.0%	0.4%	0.0%	4/
Unadjusted Volume Forecast (MDth)	40,808	53,187	34,007	
Discount Adjustment Volume (MDth)	0	224	0	5/

FOOTNOTES:

1/ ((ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT)) * 3 CENTS) + ((1 - (ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT))) * 5 CENTS)

2/ (55% * CORE PORTFOLIO PRICE) + (45% * NONCORE PORTFOLIO PRICE)

3/ ALTERNATE FUEL PRICE + GAS PREMIUM + EXIT DEMAND CHARGES - AVERAGE COST OF GAS

4/ (SEED DEFAULT RATE - MAXIMUM TRANSPORTATION RATE) / SEED DEFAULT RATE

5/ PERCENT DISCOUNT REQUIRED * UNADJUSTED VOLUME FORECAST

APPENDIX B

TABLE 1B
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED DISCOUNT ADJUSTMENT MODEL FOR P2B

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	#2 OIL	#6 OIL	PROPANE	
Alternate Fuel Price (cents/therm)	37.4	28.5	36.1	
Gas Premium (cents/therm)	2.0	2.0	2.0	
Exit Demand Charges (cents/therm)	4.4	4.4	4.4	1/
Less: Average Cost of Gas (cents/therm)	20.0	20.0	20.0	2/
Maximum Transportation Rate (cents/therm)	23.8	14.9	22.5	3/
Seed Default Rate (cents/therm)	15.8	15.8	15.8	
Percent Discount Required	0.0%	5.9%	0.0%	4/
Unadjusted Volume Forecast (MDth)	466	1,864	5,592	
Discount Adjustment Volume (MDth)	0	110	0	5/

FOOTNOTES:

1/ ((ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT)) * 3 CENTS) + ((1 - (ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT))) * 5 CENTS)

2/ (55% * CORE PORTFOLIO PRICE) + (45% * NONCORE PORTFOLIO PRICE)

3/ ALTERNATE FUEL PRICE + GAS PREMIUM + EXIT DEMAND CHARGES - AVERAGE COST OF GAS

4/ (SEED DEFAULT RATE - MAXIMUM TRANSPORTATION RATE) / SEED DEFAULT RATE

5/ PERCENT DISCOUNT REQUIRED * UNADJUSTED VOLUME FORECAST

APPENDIX B

TABLE 1C
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED DISCOUNT ADJUSTMENT MODEL FOR COGEN

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	#2 OIL	#6 OIL	PROPANE	
Alternate Fuel Price (cents/therm)	35.2	26.8	31.4	
Gas Premium (cents/therm)	2.0	2.0	2.0	
Exit Demand Charges (cents/therm)	4.4	4.4	4.4	1/
Less: Average Cost of Gas (cents/therm)	19.7	19.7	19.7	2/
Maximum Transportation Rate (cents/therm)	21.9	13.5	18.1	3/
Seed Default Rate (cents/therm)	14.9	14.9	14.9	
Percent Discount Required	0.0%	9.3%	0.0%	4/
Unadjusted Volume Forecast (MDth)	29,934	2,661	380	
Discount Adjustment Volume (MDth)	0	247	0	5/

FOOTNOTES:

1/ ((ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT)) * 3 CENTS) + ((1 - (ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT))) * 5 CENTS)

2/ (55% * CORE PORTFOLIO PRICE) + (45% * NONCORE PORTFOLIO PRICE)

3/ ALTERNATE FUEL PRICE + GAS PREMIUM + EXIT DEMAND CHARGES - AVERAGE COST OF GAS

4/ (SEED DEFAULT RATE - MAXIMUM TRANSPORTATION RATE) / SEED DEFAULT RATE

5/ PERCENT DISCOUNT REQUIRED * UNADJUSTED VOLUME FORECAST

APPENDIX B

TABLE 1C
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED DISCOUNT ADJUSTMENT MODEL FOR COGEN

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	#2 OIL	#6 OIL	PROPANE	
Alternate Fuel Price (cents/therm)	37.4	28.5	36.1	
Gas Premium (cents/therm)	2.0	2.0	2.0	
Exit Demand Charges (cents/therm)	4.4	4.4	4.4	1/
Less: Average Cost of Gas (cents/therm)	20.0	20.0	20.0	2/
Maximum Transportation Rate (cents/therm)	23.8	14.9	22.5	3/
Seed Default Rate (cents/therm)	13.9	13.9	13.9	
Percent Discount Required	0.0%	0.0%	0.0%	4/
Unadjusted Volume Forecast (MDth)	29,934	2,661	380	
Discount Adjustment Volume (MDth)	0	0	0	5/

FOOTNOTES:

1/ ((ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT)) * 3 CENTS) + ((1 - (ANNUAL NEGOTIATED VOLUMES/(1988 ESTIMATED P2B + G-IND + COGEN THROUGHPUT))) * 5 CENTS)

2/ (55% * CORE PORTFOLIO PRICE) + (45% * NONCORE PORTFOLIO PRICE)

3/ ALTERNATE FUEL PRICE + GAS PREMIUM + EXIT DEMAND CHARGES - AVERAGE COST OF GAS

4/ (SEED DEFAULT RATE - MAXIMUM TRANSPORTATION RATE) / SEED DEFAULT RATE

5/ PERCENT DISCOUNT REQUIRED * UNADJUSTED VOLUME FORECAST

TABLE 2A
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CUSTOMER CLASS	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)
CORE THROUGHPUT		
Residential IM	180,483	180,483
Residential MM	32,447	32,447
Total Residential	212,930	212,930
Small Commercial	68,353	68,353
Large Commercial Core	14,914	14,914
Large Commercial Noncore	0	0
Large Commercial Transport-Only	0	0
Total Commercial	83,267	83,267
Interdepartmental C&C	80	80
Interdepartmental OPS	97	97
PG&E Start-Up Fuel	1,474	1,474
SoCal Edison	0	0
Total Other	1,651	1,651
TOTAL CORE	297,848	297,848
NONCORE THROUGHPUT		
Large P2B Core Elect	4,185	4,007
Large P2B Noncore	1,195	1,144
Large P2B Transport-Only	2,232	2,137
Total Large P2B	7,612	7,287
Industrial Core Elect	66,898	63,009
Industrial Noncore	19,280	18,159
Industrial Transport-Only	35,452	33,391
Total Industrial	121,630	114,559
Cogeneration Core Elect	18,135	17,999
Cogeneration Noncore	5,075	5,037
Cogeneration Transport-Only	9,765	9,692
Total Cogeneration	32,975	32,728
EOR Core Elect	0	0
EOR Noncore	3,721	3,721
EOR Transport-Only	14,881	14,881
Total EOR	18,602	18,602

(Continued on Next Page)

APPENDIX B

TABLE 2A
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CUSTOMER CLASS	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)
CORE THROUGHPUT		
Residential IM	180,483	180,483
Residential MM	32,447	32,447
Total Residential	212,930	212,930
Small Commercial	68,353	68,353
Large Commercial Core	14,914	14,914
Large Commercial Noncore	0	0
Large Commercial Transport-Only	0	0
Total Commercial	83,267	83,267
Interdepartmental C&C	80	80
Interdepartmental OPS	97	97
PG&E Start-Up Fuel	1,474	1,474
SoCal Edison	0	0
Total Other	1,651	1,651
TOTAL CORE	297,848	297,848
NONCORE THROUGHPUT		
Large P2B Core Elect	4,358	4,298
Large P2B Noncore	1,242	1,225
Large P2B Transport-Only	2,322	2,290
Total Large P2B	7,922	7,812
Industrial Core Elect	70,402	70,279
Industrial Noncore	20,240	20,205
Industrial Transport-Only	37,360	37,295
Total Industrial	128,002	127,778
Cogeneration Core Elect	18,135	18,135
Cogeneration Noncore	5,075	5,075
Cogeneration Transport-Only	9,765	9,765
Total Cogeneration	32,975	32,975
EOR Core Elect	0	0
EOR Noncore	3,721	3,721
EOR Transport-Only	14,881	14,881
Total EOR	18,602	18,602

APPENDIX B

TABLE 2A
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CUSTOMER CLASS	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)	
EOR Cogeneration Core Elect	0	0	(Continued from Previous Page)
EOR Cogeneration Noncore	931	931	
EOR Cogeneration Transport-Only	17,727	17,727	
Total EOR Cogeneration	18,658	18,658	
Wholesale Core Elect	6,256	6,256	
Wholesale Noncore	0	0	
Wholesale Transport-Only	4,170	4,170	
Total Wholesale	10,426	10,426	
UEG-PG&E Core Elect	138,709	138,709	
UEG-PG&E Noncore	0	0	
UEG-PG&E Transport-Only	0	0	
Total UEG-PG&E	138,709	138,709	
UEG-SCE Core Elect	3,823	3,823	
UEG-SCE Noncore	0	0	
UEG-SCE Transport-Only	0	0	
Total UEG-SCE	3,823	3,823	
GC2-Industrial Core Elect	14,398	14,398	
GC2-Industrial Noncore	3,802	3,802	
GC2-Industrial Transport-Only	7,977	7,977	
Total GC2-Industrial	26,177	26,177	
GC2-Cogeneration Core Elect	7,163	7,163	
GC2-Cogeneration Noncore	1,974	1,974	
GC2-Cogeneration Transport-Only	3,889	3,889	
Total GC2-Cogeneration	13,026	13,026	
Steam Heat	1,033	1,033	
Interdepartmental	86	86	
TOTAL NONCORE	392,757	385,114	
OTHER THROUGHPUT			
Gas Department Use	6,061	6,061	(Continued on Next Page)
Lost and Unaccounted For Core	16,769	16,769	

APPENDIX B

TABLE 2A
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CUSTOMER CLASS	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)
EOR Cogeneration Core Elect	0	0
EOR Cogeneration Noncore	931	931
EOR Cogeneration Transport-Only	17,727	17,727
Total EOR Cogeneration	18,658	18,658
Wholesale Core Elect	6,256	6,256
Wholesale Noncore	0	0
Wholesale Transport-Only	4,170	4,170
Total Wholesale	10,426	10,426
UEG-PG&E Core Elect	138,709	138,709
UEG-PG&E Noncore	0	0
UEG-PG&E Transport-Only	0	0
Total UEG-PG&E	138,709	138,709
UEG-SCE Core Elect	3,823	3,823
UEG-SCE Noncore	0	0
UEG-SCE Transport-Only	0	0
Total UEG-SCE	3,823	3,823
GC2-Industrial Core Elect	14,398	14,398
GC2-Industrial Noncore	3,802	3,802
GC2-Industrial Transport-Only	7,977	7,977
Total GC2-Industrial	26,177	26,177
GC2-Cogeneration Core Elect	7,163	7,163
GC2-Cogeneration Noncore	1,974	1,974
GC2-Cogeneration Transport-Only	3,889	3,889
Total GC2-Cogeneration	13,026	13,026
Steam Heat	1,033	1,033
Interdepartmental	86	86
TOTAL NONCORE	399,439	399,105
OTHER THROUGHPUT		
Gas Department Use Core	5,758	5,758
Gas Department Use Noncore	303	303

APPENDIX B

TABLE 2A
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CUSTOMER CLASS	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)	
Lost and Unaccounted For Noncore	875	875	(Continued
Interutility Noncore	47,079	47,079	from Previous
Interutility Transport-Only	20,192	20,192	Page)
TOTAL OTHER	90,976	90,976	
TOTAL THROUGHPUT	781,581	773,938	

TABLE 2B
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

TYPE OF SERVICE	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)
Core Gas Requirements	297,848	297,848
Core-Elect Gas Requirements	260,686	256,482
Noncore Gas Requirements	83,057	81,847
Total Requirements	641,591	636,177
Total Transport-Only	116,285	114,055
Total Other	23,705	23,705
TOTAL THROUGHPUT	781,581	773,938

APPENDIX B

TABLE 2A
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CUSTOMER CLASS	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)
Lost and Unaccounted For Core	16,769	16,769
Lost and Unaccounted For Noncore	875	875
Interutility Noncore	47,079	47,079
Interutility Transport-only	20,192	20,192
TOTAL OTHER	90,976	90,976
TOTAL THROUGHPUT	788,263	787,929

TABLE 2B
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED THROUGHPUT

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

TYPE OF SERVICE	UNADJUSTED THROUGHPUT (MDth)	DISCOUNT ADJUSTED THROUGHPUT (MDth)
Core Gas Requirements	297,848	297,848
Core-Elect Gas Requirements	264,363	264,180
Noncore Gas Requirements	84,064	84,011
Total Requirements	646,275	646,039
Total Transport-Only	118,283	118,186
Total Other	23,705	23,705
TOTAL THROUGHPUT	788,263	787,929

APPENDIX B

TABLE 3
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED COST OF GAS

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	VOLUME (MDth)	PRICE ($/Dth)	COST ($000)
CORE:			
Supply Sources:			
California	122,815	1.800	221,067
Rocky Mountain	2,705	1.670	4,517
PGT-Canadian	368,285	1.847	680,222
El Paso	---	2.844	---
Southwest	120,428	2.100	252,899
Subtotal	614,233	1.886	1,158,706
Withdrawal from Storage	39,329	2.064	81,175
Injection to Storage	(37,190)	1.886	(70,140)
Subtotal (including storage-related transition costs)	616,372	1.898	1,169,740
Less: storage-related transition costs			(7,001)
TOTALS	616,372		1,162,740
CORE Weighted Average Cost of Gas (WACOG)		1.886	
NONCORE:			
Noncore Demand	83,057		
Noncore Gas Department Use (GDU)	6,061		
Noncore Lost and Unaccounted For (LUAF)	875		
TOTALS	89,993		170,987
NONCORE Weighted Average Cost of Gas (WACOG)		1.900	
TOTAL COST OF GAS			1,333,726

APPENDIX B

TABLE 3
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED COST OF GAS

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	VOLUME (MDth)	PRICE ($/Dth)	COST ($000)
CORE:			
Supply Sources:			
California	122,815	1.850	227,208
Rocky Mountain	2,705	1.670	4,517
PGT-Canadian	368,285	1.940	714,473
El Paso	---	2.844	---
Southwest	88,794	2.100	186,467
Subtotal	582,599	1.944	1,132,665
Withdrawal from Storage	39,329	2.050	80,629
Injection to Storage	(37,190)	1.944	(72,303)
Subtotal (including storage-related transition costs)	584,738	1.951	1,140,991
Less: storage-related transition costs			4,167
TOTALS	584,738		1,136,824
CORE Weighted Average Cost of Gas (WACOG)		1.944	
NONCORE:			
Noncore Demand	84,064		
Noncore Gas Department Use (GDU)	303		
Noncore Lost and Unaccounted For (LUAF)	875		
TOTALS	85,242		161,960
NONCORE Weighted Average Cost of Gas (WACOG)		1.900	
TOTAL COST OF GAS			1,298,784

APPENDIX B

TABLE 4
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED STORAGE-RELATED TRANSITION COSTS

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

Weighted Average Price of Withdrawals ($/Dth)	2.064
Less: Weighted average price of core gas ($/Dth)	1.886
Subtotal ($/Dth)	0.178
Volume of Withdrawals (MDth)	39,329
Storage-Related Transition Costs ($000)	7,001

APPENDIX B

TABLE 4
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED STORAGE-RELATED TRANSITION COSTS

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

Weighted Average Price of Withdrawals ($/Dth)	2.050
Less: Weighted average price of core gas ($/Dth)	1.944
Subtotal ($/Dth)	0.106
Volume of Withdrawals (MDth)	39,329
Storage-Related Transition Costs ($000)	4,167

APPENDIX B

TABLE 5

PACIFIC GAS AND ELECTRIC COMPANY

ANNUAL COST ALLOCATION PROCEEDING

ADOPTED PORTFOLIO PRICES

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CORE:	
CORE Cost of Gas ($000)	$1,053,633
Add: Purchase Gas Account ($000)	60,843
Add: Franchise Fees and Uncollectibles @ 0.00943% ($000)	10,510
TOTAL CORE COST ($000)	$1,124,985
CORE VOLUME (MDth)	558,534
CORE PORTFOLIO PRICE ($/Dth)	$2.014
NONCORE:	
NONCORE Cost of Gas ($000)	$170,987
Add: Franchise Fees and Uncollectibles @ 0.00943% ($000)	1,612
TOTAL NONCORE COST ($000)	$172,599
NONCORE VOLUME (MDth)	89,993
NONCORE PORTFOLIO PRICE ($/Dth)	$1.918

APPENDIX B

TABLE 5
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED PORTFOLIO PRICES

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

CORE:	
CORE Cost of Gas ($000) 1/	$1,093,028
Add: Purchase Gas Account ($000)	60,843
Add: Franchise Fees and Uncollectibles @ 0.00943% ($000)	10,881
TOTAL CORE COST ($000)	$1,164,752
CORE VOLUME (MDth)	562,211
CORE PORTFOLIO PRICE ($/Dth)	$2.072
NONCORE:	
NONCORE Cost of Gas ($000) 2/	$159,722
Add: Franchise Fees and Uncollectibles @ 0.00943% ($000)	1,506
TOTAL NONCORE COST ($000)	$161,228
NONCORE VOLUME (MDth)	84,064
NONCORE PORTFOLIO PRICE ($/Dth)	$1.918

FOOTNOTES:

1/ Excludes GDU and LUAF expenses of $43,796,082.

2/ Excludes GDU and LUAF expenses of $2,238,200.

APPENDIX B

TABLE 6

PACIFIC GAS AND ELECTRIC COMPANY

ANNUAL COST ALLOCATION PROCEEDING

ADOPTED REVENUE REQUIREMENT SUMMARY

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

(in Thousands of Dollars)

PROCUREMENT REVENUE REQUIREMENT		
1989 Gas Procurement Costs:		
Core/Core-Elect	$1,053,633	
Noncore	170,987	

Total 1989 Commodity Costs		$1,224,619
Core Purchased Gas Account Balance (CPGA)		60,843
Franchise Fees and Uncollectibles @ 0.00943%		11,965

Total Procurement Revenue Requirement (1)		$1,297,427
Less:Procurement Revenue at Present Rates		1,177,887

Change in Procurement Revenue Requirement (2)		$119,540
TRANSMISSION REVENUE REQUIREMENT		
1989 Forecast Costs:		
Base Revenue Fixed Costs		$1,031,782
EOR and Interutility Credits		(14,693)
Pipeline Demand Charges		174,844
Gas Storage Carrying Costs		14,726
Transition Costs		34,402
CFA Debt Service/Expense		8,342
GEDA		50,000
LUAF and GDU Gas		46,374
CPUC Fee		3,745

1989 Total Forecast Costs		$1,349,522
Balancing Account Amortization: 1/		
Core Gas Fixed Cost Balancing Account (CFCA)		$3,189
Core Implementation Balancing Account (CIBA)		50,819
Noncore Implementation Balancing Account (NIBA)		82,605
Noncore Transition Cost Account (NTCA)		2,446
Negotiated Revenue Stability Account (NRSA)		16,003
Enhanced Oil Recovery Account (EORA)		(211)
Interutility Balancing Account		(1,922)
CFA Debt Service/Expense		(8,526)

Total Forecast Account Balances		$144,403
Add: Franchise Fees & Uncollectibles @ 0.00943%		14,088

Total Transmission Revenue Requirement (3)		$1,508,013
Less:Transmission Revenue at Present Rates		1,473,104

Change In Transmission Revenue Requirement (4)		$34,909
ADOPTED REVENUE REQUIREMENT (1)+(3)		$2,805,440
TOTAL CHANGE IN REVENUE REQUIREMENT (2)+(4)		$154,449

1/ Balancing account balances are current through January 31, 1989.

APPENDIX B

TABLE 6
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED REVENUE REQUIREMENT SUMMARY

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989
(In Thousands of Dollars)

PROCUREMENT REVENUE REQUIREMENT		
1989 Gas Procurement Costs:		
Core/Core-Elect	$1,093,028	
Noncore	159,722	
Total 1989 Commodity Costs		1,252,749
Core Purchased Gas Account Balance (CPGA)		60,843
Franchise Fees and Uncollectibles		12,364
Total Procurement Revenue Requirement		$1,325,956
TRANSMISSION REVENUE REQUIREMENT		
1989 Forecast Costs:		
Base Revenue Fixed Costs (includes EOR and Interutility Credits)		$1,017,089
Pipeline Demand Charges		174,844
Gas Storage Carrying Costs		14,691
Transition Costs		31,568
CFA Debt Service/Expense		8,342
GEDA		50,000
LUAF and CDU Gas		46,034
CPUC Fee		3,795
1989 Total Forecast Costs		$1,346,364
Balancing Account Amortization: 1/		
Core Gas Fixed Cost Balancing Account (CFCA)		$3,189
Core Implementation Balancing Account (CIBA)		50,819
Noncore Implementation Balancing Account (NIBA)		82,605
Noncore Transition Cost Account (NTCA)		2,446
Negotiated Revenue Stability Account (NRSA)		16,003
Enhanced Oil Recovery Account (EORA)		(211)
Interutility Balancing Account		(1,922)
CFA Debt Service/Expense		(8,526)
Total Forecast Account Balances		$144,403
Add: Franchise Fees & Uncollectibles		4,457
Total Transmission Revenue Requirement		$1,495,224
TOTAL REVENUE REQUIREMENT		$2,821,180

1/ Balancing account balances are current through January 31, 1989.

APPENDIX B

TABLE 7
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED BASE REVENUE FIXED COSTS

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989
(in Thousands of Dollars)

BASE FIXED COSTS:	
Common Distribution	$259,991
Transmission	179,757
Storage	45,031
Customer Related	460,638
Production Related	7,399
50% Administrative and General	74,273
Franchise Fees and Uncollectibles @ 0.00943%	9,738
TOTAL BASE FIXED COSTS	$1,036,827
Less: Other Operating Expenses	(5,045)
TOTAL BASE REVENUE FIXED COSTS	$1,031,782

All information pertaining to Base Revenue Fixed Costs is based on adopted allocations from the workpapers for PG&E Attrition Resolution, G-2838 dated December 19, 1988.

TABLE 8
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED TRANSITION COSTS

FORECAST PERIOD, JANUARY 1, 1989 - DECEMBER 31, 1989
(in Thousands of Dollars)

El Paso Liquids Settlement	$27,347
Storage-Related Transition Costs	7,001
Opinion No. 270-Related Costs	0
Canadian Take-or-Pay	54
TOTAL TRANSITION COSTS	$34,402

(END OF APPENDIX B)

APPENDIX B

TABLE 7
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED BASE REVENUE FIXED COSTS

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989
(in Thousands of Dollars)

BASE FIXED COSTS:	
Common Distribution	$259,991
Transmission	179,757
Storage	45,031
Customer Related	460,638
Production Related	7,399
50% Administrative and General	74,273
Franchise Fees and Uncollectibles	9,738
TOTAL BASE FIXED COSTS	$1,036,827
Less: Other Operating Expenses	(5,045)
SUBTOTAL BASE REVENUE FIXED COSTS	$1,031,782
Less: EOR and Interutility Credits	(14,693)
TOTAL BASE REVENUE FIXED COSTS	$1,017,089

All information pertaining to Base Revenue Fixed Costs is based on adopted allocations from the workpapers for PG&E Attrition Resolution, G-2838 dated December 19, 1988.

TABLE 8
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
ADOPTED TRANSITION COSTS

FORECAST PERIOD, JANUARY 1, 1989 - DECEMBER 31, 1989
(in Thousands of Dollars)

El Paso Liquids Settlement	$27,347
Storage-Related Transition Costs	4,167
Opinion No. 270-Related Costs	0
Canadian Take-or-Pay	54
TOTAL TRANSITION COSTS	$31,568

(End of Appendix B)

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PG&E ANNUAL COST ADJUSTMENT PROCEEDING- ADOPT[illegible] COST ALLOCATION- FORECAST PERIOD, JAN 1, 1989 - [illegible]ER 1989

ENTER BACOG 0/0 FAU

CORE BACOG C/THM 18.860

NONCORE BACOG C/THM 19.000

ETAIL FAU FACTOR 0.009430

RESALE FAU FACTOR 0.007650

		SUMMARY			ALLOCATION BY CUSTOMER GROUP													
				NON-CORE	CORE			NONCORE EXCEPT ALL UEG AS CORE ELECT								WHOLESALE		
		SYSTEM	CORE	UEG AS WHOLESALE	CORE-ELECT	RESIDENT.	COMMERC. SMALL	COMMERC. LARGE	P2B LARGE	OTHER INDUSTR.	INDUST LT CNTRCT	UEG-PGAE WINTER	UEG-PGAE SUMMER	COGEN	COGEN LT CNTRCT	EOR CONT/ INTERUPTIBLE	WHOLESALE	ALLOCATION BASIS
PROCUREMENT COST OF GAS (UNADJUSTED VOLUMES)																		
PURCHASED	Rev mm$	1211.203	561.741	632.663	11.799	481.584	121.694	20.462	10.163	172.122	34.378	127.322	134.203	43.845	17.260	94.209	11.749	
CORE PGA (CPGA)	Rev mm$	50.843	32.446	27.216	0.641	23.195	7.606	1.644	0.456	7.026	1.944	7.354	7.256	1.976	0.730	0.000	0.581	AVE YEAR CORE SALES 9
FAU FOR SALES GAS	Rev mm$	11.965	5.395	8.273	0.095	3.998	1.316	0.264	0.100	1.697	0.335	1.270	1.335	0.432	0.170	0.927	0.095	SALES COSTS*FAU FACTOR
TOTAL	Rev mm$	1284.012	599.202	671.854	12.576	428.779	140.614	30.301	10.719	181.645	36.206	135.948	143.379	46.253	18.210	94.216	12.576	
SALES	CENTS/THERM	20.011	20.137	19.902	20.102	20.137	20.137	20.137	19.925	19.935	19.937	20.137	20.137	19.920	19.930	19.479	20.102	
FIXED COST BASE REVENUES & OTHER COSTS FOR TRANSPORTATION RATES (1/89 BALANCE):																		
PRODUCTION	Rev mm$	7.399	3.392	3.888	0.120	2.422	0.787	0.172	0.084	1.374	0.301	0.781	0.812	0.376	0.156	0.000	0.120	AVG YEAR THRU-PUT 4
TRANSMISSION	Rev mm$	179.737	88.927	88.067	2.763	64.437	20.814	4.356	1.936	31.774	6.961	16.463	18.787	8.665	3.457	0.000	2.763	COLD YEAR THRU-PUT 5
STORAGE	Rev mm$	45.031	26.215	17.996	0.819	19.021	5.354	1.141	0.393	5.982	1.310	2.033	0.000	1.701	0.677	0.000	0.819	COLD YEAR PEAK SEASON 6
DISTRIBUTION	Rev mm$	259.991	224.453	35.538	0.000	172.477	42.714	9.262	2.151	23.058	5.051	0.000	0.000	3.775	1.503	0.000	0.000	COLD YEAR PEAK MONTH 8
CUSTOMER	Rev mm$	460.636	449.746	10.685	0.207	412.077	36.963	0.906	0.242	6.650	1.437	0.498	0.657	0.816	0.335	0.000	0.207	WGHTD CUST BY INVEST 9
50% A&G	Rev mm$	74.373	34.325	39.348	0.600	24.916	8.064	1.743	0.848	13.906	3.046	8.007	8.223	3.004	1.514	0.000	0.600	AVE YR. ADJ W/SALE 4
OTHER OP.REV.	Rev mm$	-5.043	-4.062	-0.960	-0.022	-3.421	-0.558	-0.084	-0.020	-0.406	-0.089	-0.168	-0.140	-0.094	-0.037	0.000	-0.022	% EMBEDDED COST ALLOC 10
FAU FOR FIXED CSTS	Rev mm$	9.734	7.853	1.856	0.034	6.612	1.078	0.153	0.054	0.786	0.172	0.320	0.271	0.112	0.072	0.000	0.034	FAU FACTORS EXCL U WSL
BASE (MARGIN)	Rev mm$	1031.782	830.849	196.417	4.522	699.961	114.029	17.259	5.640	83.127	18.209	33.846	28.650	15.249	7.660	0.000	4.522	
EOR CONTRIBUTION	Rev mm$	-7.293	-5.411	-1.805	-0.047	-4.507	-0.803	-0.131	-0.047	-0.719	-0.157	-0.344	-0.292	-0.176	-0.070	0.000	-0.047	
INTERUTILITY TRANS.	Rev mm$	-7.400	-3.641	-3.625	-0.114	-2.653	-0.826	-0.170	-0.080	-1.308	-0.287	-0.671	-0.773	-0.356	-0.142	0.000	-0.114	COLD YEAR THRU-PUT 5
ADJUSTED BASE	Rev mm$	1017.089	821.748	190.986	4.361	692.401	112.397	16.949	5.553	81.100	17.766	32.825	27.584	14.712	7.447	0.000	4.361	
PIPE DEMAND	Rev mm$	174.844	86.497	85.640	2.688	62.695	19.564	4.337	1.883	30.910	6.771	16.013	18.273	8.447	3.362	0.000	2.688	COLD YEAR THRU-PUT 5
C.G. INVENTORY	Rev mm$	14.726	8.573	5.885	0.268	6.482	1.718	0.373	0.129	1.956	0.429	2.594	0.000	0.556	0.221	0.000	0.268	COLD YEAR PEAK SEASON 6
TRANS COST T-OR-P	Rev mm$	27.481	12.629	14.329	0.443	9.023	2.965	0.641	0.309	5.075	1.112	2.867	3.026	1.390	0.553	0.000	0.443	AVE YEAR THRU-PUT
TRANS COST STORAGE	Rev mm$	7.001	3.463	3.430	0.108	2.510	0.783	0.170	0.075	1.238	0.271	0.641	0.732	0.338	0.135	0.000	0.108	COLD YEAR THRU-PUT 5
CFA DEBT	Rev mm$	1.762	1.164	0.598	0.000	0.831	0.273	0.059	0.029	0.468	0.102	0.000	0.000	0.000	0.000	0.000	0.000	AVE YR.ADJ UEG.COG.WHEE
CFA EXPENSES	Rev mm$	5.580	4.345	2.235	0.000	3.184	1.020	0.220	0.106	1.746	0.382	0.000	0.000	0.000	0.000	0.000	0.000	AVE YR.ADJ UEG.COG.WHEE
GEDA	Rev mm$	50.000	23.845	26.147	0.808	18.465	5.411	1.169	0.565	9.260	2.028	5.231	5.517	2.536	1.009	0.000	0.808	AVE YEAR THRU-PUT
GAS DEPT USE & LUAF	Rev mm$	40.374	17.962	27.663	0.748	12.702	4.329	0.935	0.580	9.647	1.995	7.644	4.374	2.442	0.965	0.000	0.748	AVE YR UNADJ. THRU-PUT
CPUC FEE	Rev mm$	3.745	2.229	1.516	0.000	1.603	0.514	0.112	0.057	0.915	0.197	0.000	0.000	0.248	0.098	0.000	0.000	EQUAL CENTS PER THERM
BALANCING ACCOUNTS																		
CIBA (IMPLEMENT-C)	Rev mm$	50.819	50.819	0.000	0.000	36.308	11.932	2.579	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	CORE =CENT/THM
NIBA (IMPLEMENT-NC)	Rev mm$	82.685	0.000	82.685	0.000	0.000	0.000	0.000	1.784	29.255	6.408	16.527	17.430	8.012	3.189	0.000	0.000	NONCORE =CENT/THM
NTCA (N-CORE TRANS)	Rev mm$	2.446	0.000	2.446	0.000	0.000	0.000	0.000	0.653	0.866	0.190	0.489	0.516	0.237	0.094	0.000	0.000	NONCORE =CENT/THM
NRSA	Rev mm$	16.003	7.336	8.409	0.259	5.239	1.724	0.373	0.181	2.972	0.651	1.711	1.757	0.813	0.324	0.000	0.259	= ALL CUS CENTS/THM
EORA (EOR ACCT.)	Rev mm$	-0.211	-0.157	-0.052	-0.001	-0.130	-0.023	-0.004	-0.001	-0.021	-0.005	-0.010	-0.008	-0.005	-0.002	0.000	-0.001	
ABS IBA (INTER UTL)	Rev mm$	-1.922	-0.951	-0.942	-0.030	-0.689	-0.215	-0.047	-0.021	-0.340	-0.074	-0.176	-0.201	-0.093	-0.037	0.000	-0.030	COLD YEAR THRU-PUT 5
CFA DEBT SERVICE	Rev mm$	-4.874	-3.219	-1.655	0.000	-2.300	-0.756	-0.163	-0.079	-1.293	-0.283	0.000	0.000	0.000	0.000	0.000	0.000	=C/THM.ADJ UEG.COG.WHL
CFA EXPENSES	Rev mm$	-3.652	-2.412	-1.240	0.000	-1.723	-0.566	-0.122	-0.059	-0.969	-0.212	0.000	0.000	0.000	0.000	0.000	0.000	=C/THM.ADJ UEG.COG.WHL
CSA (COGEN)	Rev mm$	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	=C/THM.UEG COGEN ONLY
CORE FIXED (CFCA)	Rev mm$	3.189	3.189	0.000	0.000	2.278	0.749	0.162	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	CORE =CENT/THM
FBUC NONBASE FC & BAL	Rev mm$	4.467	2.023	2.424	0.040	1.456	0.466	0.101	0.053	0.865	0.188	0.505	0.485	0.235	0.093	0.000	0.040	=% BAL RISC+SHRINK+DEMAND
SUBTOTAL FIXED, OTHER & BALANCING ACCT. COSTS	Rev mm$	1498.412	1038.283	450.444	9.691	848.357	162.282	27.744	11.198	173.648	37.916	84.878	79.483	43.869	17.452	0.000	9.691	
ADJUSTMENTS																		
G-10 EMPLYEE ADJUST	Rev mm$	0.856	0.689	0.163	0.004	0.508	0.095	0.014	0.005	0.069	0.015	0.036	0.024	0.016	0.006	0.000	0.004	=% OF EMBEDDED COST MARGIN
GC-2 SHORTFALL	Rev mm$	-34.329	0.000	-34.329	0.000					-23.895				-10.434				
GC-2 SHORTFALL ALLO	Rev mm$	34.329	16.756	16.982	0.591	11.960	3.938	0.851	0.414	6.788		3.909	4.014	1.857		0.000	0.591	EQUAL C/THM.THRU-PUT 4
TOTAL TRANSPORT COSTS	Rev mm$	1499.268	1055.728	433.259	10.286	860.605	166.314	28.609	11.616	158.506	14.036	90.814	83.521	45.742	7.025	0.000	10.286	
TRANSPORT RATE	CENTS/THERM	19.360	35.499	9.883	9.866	40.512	23.818	11.954	13.939	5.185	5.342	13.432	11.730	13.976	5.393	n/a	9.856	

APPENDIX C
TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY 1989 ACAP
REVENUE REQUIREMENT CHANGE
(In Thousands of Dollars)

PROCUREMENT REVENUE REQUIREMENT	
Total Procurement Revenue Requirement	$1,325,956
Less Procurement Revenue Requirement @ Present Rates	1,186,530
Change in Procurement Revenue Requirement:	139,426
Core	74,253
Core-Elect, Core-Elect Wholesale	65,173
Noncore	0
Total Change	$139,426
TRANSMISSION REVENUE REQUIREMENT	
Total Transmission Revenue Requirement	$1,495,224
Less Transmission Revenue Requirement & Present Rates	1,490,689
Change in Transmission Revenue Requirement:	4,535
Core	9,438
Noncore	(4,902)
Total Change	$4,535
TOTAL REVENUE REQUIREMENT	
Total Revenue Requirement	$2,821,180
Less Revenue Requirement @ Present Rates	2,677,219
TOTAL CHANGE IN REVENUE REQUIREMENT	$143,962

APPENDIX C
TABLE 2
PG&E ANNUAL COST ALLOCATION PROCEEDING

DETAIL UNDERLYING ADOPTED COST ALLOCATION:
BASIS FOR ADJUSTING CUSTOMER AND DEMAND CHARGE REVENUES
TO RECOVER RETURN AND TAXES FROM VOLUMETRIC CHARGES 1/

	SYSTEM PERCENT	SYSTEM DEPRECIATED RATEBASE ($000'S)	RTN BASED ON: WT COST OF ROE & PRFD OF 6.70%	TAXES STATE ($000'S)	TAXES FEDERAL ($000'S)	TOTAL ($000'S)
				33,496	112906	
TOTAL DEPR RB		1,972,151	132,134			
PRODUCTION	0.00075	1,473	99	25	84	208
STORAGE	0.07657	151,017	10,118	2,565	8,646	21,329
DISTRIBUTION	0.27275	537,905	36,040	9,136	30,795	75,971
CUSTOMER	0.38597	761,182	50,999	12,928	43,578	107,505
TRANSMISSION	0.26396	520,573	34,878	8,842	29,803	73,523
	1.00000	1972150	132,134	33,496	112,906	278,536
						278536.117

1/ Depreciated rate base and state and federal taxes reflect PG&E base cost revenues updated to reflect its 1989 Attrition Resolution, G-2838 (12/19/88). Return (i.e., weighted cost of preferred and common equity) reflects financial attrition authorized in D. 88-12-094 (12/19/88).

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APPENDIX C - Table 2

PG&E ANNUAL COST ADJUSTMENT PROCEEDING - ADOPTED COST ALLOCATION

FORECAST PERIOD, JAN 1, 1989 - DEC 1989

PROCUREMENT COST	UNADJUSTED VOLUMES:																		
PURCHASED	Rev.M$	1252.749	379.068	661.523	12.163	413.970	135.735	29.139	30.032	[illegible]932	35.216	131.240	130.422	41.930	17.677	98.299	12.113		
CORE PGA (CPGA)	Rev.M$	68.843	32.333	27.933	0.677	33.043	7.557	1.633	0.473	8.154	3.550	7.306	7.705	1.963	0.775	0.000	0.677	AVE YEAR CORE SALES	1
F&U FOR SALES GAS	Rev.M$	12.368	5.765	6.582	0.098	4.121	1.351	0.292	0.107	1.821	0.347	1.307	1.378	0.442	0.174	0.927	0.098	SALES COSTS*F&U FACTOR	
TOTAL	Rev.M$	1325.957	417.062	695.957	12.938	448.134	144.663	31.265	31.411	104.910	37.121	139.860	147.507	43.364	18.626	98.216	12.938		
SALES	CENTS/THERM	20.517	20.217	20.339	20.601	20.212	20.212	20.217	20.378	20.392	20.396	20.217	20.217	20.388	20.385	10.179	20.641		
FIXED COST BASE REVENUES & OTHER COSTS FOR TRANSPORTATION RATES 88/89 BALANCE:																			
PRODUCTION*	Rev.M$	7.399	3.338	3.944	0.117	2.385	0.724	0.165	0.048	1.690	0.294	0.258	0.709	0.378	0.148	0.000	0.117	AVG.YEAR THRU-PUT	4
TRANSMISSION*	Rev.M$	179.753	83.561	85.455	2.765	63.487	19.788	4.285	3.027	34.465	5.198	15.273	18.467	6.555	5.388	0.000	2.765	COLD YEAR THRU-PUT	5
STORAGE*	Rev.M$	45.031	25.985	18.238	0.807	19.653	5.203	0.138	0.416	6.532	1.288	2.651	0.000	1.647	0.666	0.000	0.807	COLD YEAR PEAK SEASON	6
DISTRIBUTION*	Rev.M$	259.981	222.378	37.613	0.000	178.929	42.281	0.165	2.266	25.184	4.963	0.000	0.000	3.742	1.478	0.000	0.000	COLD YEAR PEAK MONTH	8
CUSTOMER*	Rev.M$	460.638	449.748	10.685	0.207	412.677	36.563	0.504	0.242	6.778	1.336	0.458	0.697	0.817	0.333	0.000	0.207	WGTD CUST.BY INVESTM.	8
SOG ADJ*	74.273	74.273	33.248	39.870	0.646	24.112	7.924	0.733	0.887	15.061	2.171	2.640	0.000	3.242	1.478	0.000	0.646	AVE.YR.:ADJ WHSALE	8
OTHER OP.REV.*	Rev.M$	-5.045	-0.841	-0.982	-0.022	-3.405	-0.553	-0.063	-0.020	-0.440	-0.087	-0.155	-0.138	-0.053	-0.037	0.000	-0.022	% EMBEDDED COST MARG.18	
F&U FOR FIXED CSTS*	9.238	9.238	7.807	1.496	0.034	6.578	1.068	0.161	0.056	0.149	0.167	0.307	0.264	0.179	0.071	0.000	0.034	F&U FACTORS EXCL U WHSL	
BASE (MARGIN)	Rev.M$	1031.782	826.531	200.766	4.494	696.415	113.858	17.048	5.951	88.896	17.738	32.481	28.192	11.008	7.306	0.000	4.494		
EOR CONTRIBUTION *	Rev.M$	-7.293	-5.510	-1.740	-0.043	-4.582	-0.800	-0.128	-0.048	-0.746	-0.147	-0.289	-0.279	-0.165	-0.065	0.000	-0.043	BASE+PIPELINE DEMAND	
INTERRUPTIBLE TRANS.*	Rev.M$	-7.400	-3.605	-3.644	-0.111	-2.613	-0.815	-0.176	-0.083	-1.419	-0.280	-0.649	-0.761	-0.352	-0.139	0.000	-0.111	COLD YEAR THRU-PUT	5
ADJUSTED BASE	Rev.M$	1017.088	817.406	195.343	4.340	689.219	111.443	16.744	5.820	87.231	17.304	31.553	27.151	10.493	7.301	0.000	4.340		
PIPE DEMAND *	Rev.M$	124.844	85.150	87.845	2.631	61.732	19.247	0.165	1.372	33.527	0.613	15.388	12.982	3.322	3.217	0.000	2.631	COLD YEAR THRU-PUT	5
C.C.INVENTORY *	Rev.M$	12.695	0.477	3.050	0.263	0.411	1.697	0.368	0.135	2.131	0.420	2.498	0.000	0.558	0.217	0.000	0.263	COLD YEAR PEAK SEASON	6
TRANS.CST CAN T-O-P	Rev.M$	0.034	0.024	0.029	0.001	0.017	0.006	0.006	0.001	0.011	0.002	0.006	0.006	0.003	0.001	0.000	0.001	AVE YEAR THRU-PUT:VOLUMES	7
TRANS COST.STORAGE*	Rev.M$	4.167	2.030	2.075	0.063	1.472	0.459	0.059	0.047	0.799	0.158	0.366	0.429	0.118	0.078	0.000	0.063	COLD YEAR,THRU-PUT	5
CFA DEBT *	Rev.M$	0.762	0.129	0.633	0.000	0.007	0.263	0.057	0.030	0.504	0.011	0.000	0.000	0.000	0.000	0.000	0.000	AVE YR:ADJ.UEG.COL.MULE	
CFA EXPENSES *	Rev.M$	6.560	4.216	2.344	0.000	3.012	0.998	0.214	0.111	1.682	0.374	0.000	0.000	0.000	0.000	0.000	0.000	AVE YR:ADJ.UEG.COL.MULE	
GEDA & EE PASS LIQ*	Rev.M$	77.347	34.093	41.238	1.233	24.930	8.193	1.773	0.917	15.572	3.076	7.921	8.354	3.869	1.320	0.000	1.233	AVE YEAR THRU-PUT: 01	
GAS DEPT USE & LUAF	Rev.M$	46.834	20.776	24.333	0.727	14.050	4.870	1.053	0.553	9.272	1.826	4.700	4.966	2.300	0.909	0.000	0.727	AVE YR UNADJ. THRU-PUT	
CPUC FEE	Rev.M$	3.705	3.229	0.568	0.000	1.603	0.514	0.112	0.060	0.963	0.197	0.000	0.000	0.248	0.098	0.000	0.000	EQUAL CENTS PER THERM	
BALANCING ACCOUNTS																			
CIBA*(IMPLEMENT-C)	Rev.M$	50.819	50.819	0.000	0.000	36.308	11.932	2.578	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	CORE CENT/THM	
NIBA*(IMPLEMENT-NC)	Rev.M$	83.605	0.000	83.605	0.000	0.000	0.000	0.000	5.837	31.557	6.155	15.569	16.736	7.751	3.063	0.000	0.000	NCORE EXC WHSL & EOR C/TH	
NTCA*(N-CORE TRANS)	Rev.M$	2.448	0.000	2.376	0.070	0.000	0.000	0.000	0.053	0.897	0.177	0.456	0.481	0.223	0.088	0.000	0.070	NCORE EXCL EOR ONLY C/TH	
MBSA *	Rev.M$	16.003	0.000	15.542	0.461	0.000	0.000	0.000	0.346	5.870	1.158	2.986	3.149	1.458	0.576	0.000	0.461	NCORE EXCL EOR ONLY C/TH	
EORA (EOR ACCT.)*	Rev.M$	-0.210	-0.159	-0.050	-0.001	-0.133	-0.023	-0.004	-0.001	-0.022	-0.004	-0.004	-0.008	-0.005	-0.002	0.000	-0.001	BASE+PIPELINE DEMAND	
ABS IBA*(INTER UTL)	Rev.M$	-1.928	-0.936	-0.957	-0.029	-0.679	-0.212	-0.046	-0.022	-0.369	-0.073	-0.169	-0.198	-0.041	-0.036	0.000	-0.029	COLD YEAR THRU-PUT	5
CFA DEBT SERVICE *	Rev.M$	-4.874	-3.133	-1.751	0.000	-2.331	-0.733	-0.158	-0.082	-1.394	-0.275	0.000	0.000	0.000	0.000	0.000	0.000	C/THM;ADJ UEG.COG.MUL	
CFA EXPENSES *	Rev.M$	-3.652	-2.348	-1.312	0.000	-1.672	-0.549	-0.119	-0.061	-1.044	-0.206	0.000	0.000	0.000	0.000	0.000	0.000	C/THM;ADJ UEG.COG.MUL	
CSA (COGEN) *	Rev.M$	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	C/THM,UEG COGEN ONLY	
CORE FIXED (CFCA) *	Rev.M$	3.119	3.119	0.000	0.000	2.370	0.749	0.162	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	CORE CENT/THM	
FRANCHISE FC & BAL	Rev.M$	4.437	1.946	2.470	0.041	1.403	0.447	0.097	0.056	0.944	0.186	0.474	0.485	0.234	0.092	0.000	0.041	% BAL BASE+PIPELINE DEMAND	
SUBTOTAL FIXED, OTHER & BALANCING ACCT. COSTS	Rev.M$	1495.314	1025.742	459.591	9.761	839.345	155.295	17.835	11.747	118.469	37.375	81.998	70.537	43.343	17.301	0.000	9.751		
ADJUSTMENTS G-10 FIX		-0.333	-0.333	0.000	0.000	-0.333													
G-10 EMPLYEE ADJUST	Rev.M$	0.533	0.147	0.183	0.004	0.636	0.102	0.015	0.005	0.041	0.016	0.029	0.029	0.017	0.007	0.000	0.004	% OF EMBEDDED COST MARGIN	
GC-2 SHORTFALL	Rev.M$	-33.340	0.000	-33.340	0.000						-23.357				-10.103				
GC-2 SHORTFALL ALLO	Rev.M$	33.340	15.551	16.788	0.561	11.835	3.555	0.811	0.338	3.136		3.630	3.826	1.173		0.000	0.561	EQUAL C/THM,THRU-PUT	6
TOTAL TRANSPORT COSTS	Rev.M$	1495.324	1041.348	443.320	10.355	850.470	163.152	37.925	12.193	115.088	14.038	85.857	83.391	45.333	7.024	0.000	10.355		
TRANSPORT RATE	CENTS/THERM	20.896	35.022	12.815	9.511	40.020	33.563	18.305	19.606	10.744	9.363	12.608	11.712	13.748	1.393	N/A	9.511		

APPENDIX C

TABLE 3

PACIFIC GAS AND ELECTRIC COMPANY 1989 ACAP

ADOPTED CORE RATES AND REVENUES

(EFFECTIVE 4/1/89)

CLASS OF SERVICE	ADJUSTED CUST/SALES FORECAST (MTH/CUST)	PRESENT RATES 1/ ($/TH &/MO) (1/1/89)	PRESENT REVENUES (M$)	ADOPTED RATES ($/TH &/MO)	ADOPTED REVENUES (M$)	ADOPTED CHANGE (%)
	(a)	(b)	(c)	(d)	(e)	(f)
RESIDENTIAL						
Tier I (Baseline)	1,524,898	0.41644	635,029	0.44659	681,005	7.2%
Tier II	599,899	0.82146	492,793	0.84682	508,007	3.1%
GS,GT Adj.			(6,860)		(6,860)	0.0%
TOTAL RESIDENTIAL	2,124,797	0.52756	1,120,962	0.55636	1,182,152	5.5%
SMALL COMMERCIAL SCHEDULE G-NR1						
Cust Charg($/MO)	2359.584	12.12	28,598	11.88	28,030	-2.0%
Summer Rate	334,820	0.43233	144,753	0.45482	152,283	5.2%
Winter Rate	363,450	0.58364	212,124	0.61400	223,159	5.2%
Total G-NR1	698,270	0.55204	385,475	0.57782	403,472	4.7%
LARGE COMMERCIAL SCHEDULE G-NR2						
Cust Charg($/MO)	2.856	138.52	396	135.85	388	-1.9%
Summer Rate	72,130	0.37350	26,941	0.38430	27,719	2.9%
Winter Rate	78,780	0.50423	39,723	0.51879	40,871	2.9%
Total G-NR2	150,910	0.44437	67,060	0.45708	68,978	2.9%
COMMERCIAL (TRANSPORT ONLY) SCHEDULE G-NR3						
Cust Charg($/MO)		138.52	0	135.85	0	-1.9%
Summer Rate	0	0.19098	0	0.18293	0	-4.2%
Winter Rate	0	0.32171	0	0.31742	0	-1.3%
Total G-NR3	0	0.33154	0	0.35499	0	7.1%
Total Commercial	849,180	0.53291	452,535	0.55636	472,450	4.4%
TOTAL CORE	2,973,977	0.52909	1,573,497	0.55636	1,654,603	5.2%

1/ CPUC surcharge of $.00076/therm reflected in present rates, except for PG&E and SCE volumes.

APPENDIX C
TABLE 3
PG&E ANNUAL COST ALLOCATION PROCEEDING

DETAIL UNDERLYING ADOPTED COST ALLOCATION:
BASIS FOR ADJUSTING CUSTOMER AND DEMAND CHARGE REVENUES
TO RECOVER RETURN AND TAXES FROM VOLUMETRIC CHARGES 1/

	SYSTEM PERCENT	SYSTEM DEPRECIATED RATEBASE ($000'S)	RTN BASED ON: WT COST OF ROE & PRFD OF 6.70%	TAXES STATE ($000'S)	TAXES FEDERAL ($000'S)	TOTAL ($000'S)
				33,496	112906	
TOTAL DEPR RB		1,972,151	132,134			
PRODUCTION	0.00075	1,473	99	25	84	208
STORAGE	0.07657	151,017.	10,118	2,565	8,646	21,329
DISTRIBUTION	0.27275	537,905	36,040	9,136	30,795	75,971
CUSTOMER	0.38597	761,182	50,999	12,928	43,578	107,505
TRANSMISSION	0.26396	520,573	34,878	8,842	29,803	73,523
	1.00000	1972150	132,134	33,496	112,906	278,536
						278536.117

1/ Depreciated rate base and state and federal taxes reflect PG&E base cost revenues updated to reflect its 1989 Attrition Resolution, G-2838 (12/19/88). Return (i.e., weighted cost of preferred and common equity) reflects financial attrition authorized in D. 88-12-094 (12/19/88).

APPENDIX C
TABLE 4
PACIFIC GAS AND ELECTRIC COMPANY 1989 ACAP
ADOPTED NONCORE TRANSPORT RATES AND REVENUES
(EFFECTIVE 4/1/89)

NONCORE CUSTOMER CLASS	ADJUSTED FORECAST DELIVERIES (MTH)	HISTORICAL BILLING DETERMINANTS (MTH/CUST)	PRESENT RATES EFFECTIVE 1/1/89 $/TH OR $/MO	PRESENT REVENUES 1/ EFFECTIVE 1/1/89 (M$)	ADOPTED RATE $/TH OR $/MO	ADOPTED REVENUES TOTAL NON-GAS (M$)	ADOPTED CHANGE ($/TH OR $/MO)	ADOPTED CHANGE (%)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
PRIORITY P2B								
Customer Charge		74	157.45 1/	139	203.95	186	46.50	29.5%
Demand Charge D1		74,257	0.08844	6,567	0.08088	6,006	-0.00756	-8.5%
Demand Charge D2:								
Summer		100,898	0.01513	1,527	0.01069	1,079	-0.00444	-29.3%
Winter		44,495	0.03436	1,529	0.01750	778	-0.01686	-49.1%
Volumetric Charg	72,880		0.04353	3,172	0.04894	3,567	0.00541	12.4%
TOT/AVE P2B	72,880		0.17748	12,935	0.15939	11,616	-0.01809	-10.2%
INDUSTRIAL G-IND								
Customer Charge		849	555.98 1/	5,665	500.31	5,098	-55.67	-10.0%
Demand Charge D1		1,206,072	0.05963	71,918	0.08178	98,629	0.02215	37.1%
Demand Charge D2:								
Summer		1,414,172	0.00671	9,489	0.00702	9,934	0.00031	4.7%
Winter		828,458	0.02238	18,541	0.01387	11,491	-0.00851	-38.0%
Volumetric Charg	1,195,010		0.04325	51,647 2/	0.04632	55,353	0.00307	7.1%
INDUST Net of GC-2	1,195,010		0.13160	157,260	0.15105	180,505	0.01945	14.8%
GC-2 Industrial	261,770			14,036		14,036	0	0.0%
TOTAL INDUSTRIAL	1,456,780		0.11759	171,296	0.13354	194,540	0.01596	13.6%
UTILITY ELEC GEN								
Customer Charge		1	74,727.00	897	99,615.22	1,195	24,888	33.3%
Demand Charge			1/	166,082	1/	141,133	(24,949)	-15.0%
Volumetric Charg:								
Tier I	320,580		0.04469	14,327	0.04522	14,498	0.00053	1.2%
Tier II	1,066,510		0.01439	15,347	0.01991	21,237	0.00552	38.4%
TOT/AVE UEG	1,387,090		0.14177	196,653	0.12837	178,063	-0.01340	-9.5%
COGENERATION								
Cogen NetofGC-2	327,280		0.13828	45,256	0.128372	42,014	-0.00991	-7.2%
GC-2 Cogen	130,260			7,024		7,024	0.00	0.0%
TOT/AVE COGEN	457,540		0.11426	52,281	0.10718	49,038	-0.00709	-6.2%
NONCORE SUBTOTAL								
Net of GC-2	2,982,260		0.13819	412,104	0.13822	412,198	0.00003	0.0
Including GC-2	3,374,290		0.12837	433,164	0.12840	433,257	0.00003	0.0%
WHOLESALE								
Demand Charges			1/	8,931	1/	9,023	92	1.0%
Volumetric Charg	104,270		0.01040	1,084	0.01212	1,264	0.00172	16.5%
TOT/AVE WHOLESALE	104,270		0.09605	10,015	0.09865	10,286	0.00260	2.7%
TOT NONCORE	3,086,530							
Net of GC-2	3,086,530		0.13676	422,119	0.13688	422,484	0.00012	0.1%
Including GC-2	3,478,560		0.12740	443,179	0.12751	443,544	0.00010	0.1%

1/ Customer and demand charges for these schedule are tiered.

2/ Revenues reflect exclusion of 49.4 MMTH from CPUC surcharge fee of .0076/therm.

(END OF APPENDIX C)

APPENDIX C-4

ADOPTED CORE RATES AND REVENUES

CLASS OF SERVICE	ADJUSTED CUST/SALES FORECAST (MTH/CUST)	PRESENT RATES ($/TH &/MO)	PRESENT REVENUES (M$)	ADOPTED RATES ($/TH &/MO)	ADOPTED REVENUES (M$)	ADOPTED RATE CHANGE (%)
	(a)	(b)	(c)	(d)	(e)	(f)
RESIDENTIAL						
	2/		2/			
Tier I (Baseline)	1,485,959	0.41122	611,056	0.44061	654,723	7.1%
Tier II	638,838	0.81116	518,200	0.84084	537,158	3.7%
GS,GT Adj.			(6,860)		(6,860)	0.0%
TOTAL RESIDENTIAL	2,124,797	0.52824	1,122,396	0.55771	1,185,021	5.6%
SMALL COMMERCIAL						
SCHEDULE G-NR1 1/						
Cust Charg($/MO)	2359.584	12.12	28,598	11.88	28,030	-2.0%
Summer Rate	334,820	0.43233	144,747	0.45635	152,797	5.6%
Winter Rate	363,450	0.58364	212,119	0.61608	223,916	5.6%
Total G-NR1	698,270	0.55203	385,464	0.57964	404,742	5.0%
LARGE COMMERCIAL						
SCHEDULE G-NR2						
Cust Charg($/MO)	2.856	138.52	396	135.85	388	-1.9%
Summer Rate	72,130	0.37350	26,941	0.38360	27,669	2.7%
Winter Rate	78,780	0.50423	39,723	0.51786	40,797	2.7%
Total G-NR2	150,910	0.44437	67,060	0.45626	68,854	2.7%
0.55771						
COMMERCIAL (TRANSPORT ONLY)						
SCHEDULE G-NR3						
Cust Charg($/MO)		138.52	0	135.85	0	-1.9%
Summer Rate	0	0.19098	0	0.17643	0	-7.6%
Winter Rate	0	0.32171	0	0.31069	0	-3.4%
Total Commercial	849,180	0.53289	452,523	0.55771	473,596	4.7%
TOTAL CORE	2,973,977	0.52957	1,574,919	0.55771	1,658,610	5.3%

1/ CPUC surcharge of $.00076/therm reflected in rates, except for PG&E and SCE-UEG volumes.

2/ TI and TII sales realigned reducing baseline quantities & rates (AL 1539-G).

APPENDIX D

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
COMPARISON SUMMARY

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	ADOPTED	CIG	DRA	PG&E
CORE Weighted Average Cost of Gas (WACOG) ($/Dth)	1.886	1.684 /1	1.871 /2	1.920 /3
NONCORE Weighted Average Cost of Gas (WACOG) ($/Dth)	1.900	1.880 /1	1.969 /2	2.200 /3
Gas Prices by Supply Source:				
California	1.800	1.558 /1	1.700 /4	1.850 /3
Rocky Mountain	1.670	1.350 /1	1.670 /4	1.670 /3
PGT- Canadian	1.847	1.611 /1	1.847 /4	1.847 /3
El Paso	2.844	-- /1	2.844 /4	2.844 /3
Southwest	2.100	2.014 /1	2.030 /4	2.200 /3
Adjusted Industrial Throughput (MDth)	157,581	140,700 /5	159,877 /6	140,785 /6
Revenue Requirement ($000)	2,804,250	--	2,736,853 /7	2,656,656 /7

/1 Exhibit 56, Table 2.

/2 Exhibit 51, Table 4-1.

/3 Exhibit 20, page MAS-4.

/4 DRA Opening Brief, pages 26 and 27.

/5 Exhibit 57, page 8.

/6 Exhibit 50, Table 3-1.

/7 Exhibit 52, Table 6-1.

(END OF APPENDIX D)

APPENDIX D

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL COST ALLOCATION PROCEEDING
COMPARISON SUMMARY

FORECAST PERIOD: JANUARY 1, 1989 TO DECEMBER 31, 1989

	ADOPTED	CIG	DRA	PG&E
CORE Weighted Average Cost of Gas (WACOG) ($/Dth)	1.944	1.684 /1	1.871 /2	1.920 /3
NONCORE Weighted Average Cost of Gas (WACOG) ($/Dth)	1.900	1.880 /1	1.969 /2	2.200 /3
Gas Prices by Supply Source:				
California	1.850	1.558 /1	1.700 /4	1.850 /3
Rocky Mountain	1.670	1.350 /1	1.670 /4	1.670 /3
PGT- Canadian	1.940	1.611 /1	1.847 /4	1.847 /3
El Paso	2.844	-- /1	2.844 /4	2.844 /3
Southwest	2.100	2.014 /1	2.030 /4	2.200 /3
Adjusted Industrial Throughput (MDth)	168,565 /5	140,700 /6	159,877 /7	140,785 /7
Revenue Requirement ($000)	2,821,180	--	2,736,853 /8	2,656,656 /8

/1 Exhibit 56, Table 2.

/2 Exhibit 51, Table 4-1.

/3 Exhibit 20, page MAS-4.

/4 DRA Opening Brief, pages 26 and 27.

/5 Includes throughput estimates for P2B, G-IND, and COGEN customer classes.

/6 Exhibit 57, page 8.

/7 Exhibit 50, Table 3-1.

/8 Exhibit 52, Table 6-1.

(End of Appendix D)

APPENDIX C-5

ADOPTED NONCORE TRANSPORT RATE AND REVENUES

NONCORE CUSTOMER CLASS	ADJUSTED FORECAST DELIVERIES (MTH)	HISTORICAL BILLING DETERMINANTS (MTH/CUST)	PRESENT RATES $/TH OR $/MO	PRESENT REVENUES (M$)	ADOPTED RATE $/TH OR $/MO	ADOPTED REVENUES TOTAL NON-GAS (M$)	ADOPTED RATE CHANGE (%)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
PRIORITY P2B							
Customer Charge		76	156.80 3/	143	203.64	186	29.9%
Demand Charge D1		79,596	0.08844	7,039	0.08408	6,692	-4.9%
Demand Charge D2:							
Summer		108,153	0.01513	1,636	0.01029	1,113	-32.0%
Winter		47,694	0.03436	1,639	0.01770	844	-48.5%
Volumetric Charg	78,120		0.04353	3,401	0.04298	3,358	-1.3%
TOT/AVE P2B	78,120		0.17740	13,858	0.15608	12,193	-12.0%
INDUSTRIAL G-IND 1/							
Customer Charge		860	554.84 3/	5,726	503.01	5,191	-9.3%
Demand Charge D1		1,339,485	0.05963	79,874	0.08500	113,850	42.5%
Demand Charge D2:							
Summer		1,570,605	0.00671	10,539	0.00715	11,231	6.6%
Winter		920,101	0.02238	20,592	0.01320	12,148	-41.0%
Volumetric Charg	1,327,200		0.04325	57,364 4/	0.04013	53,265	-7.2%
INDUST Net of GC-2	1,327,200		0.13117	174,094	0.14744	195,686	12.4%
GC-2 Industrial	261,770			13,530		14,036	3.7%
	----------		---------	---------	---------	---------	---------
TOTAL INDUSTRIAL	1,588,970		0.11808	187,624	0.13199	209,722	11.8%
UTILITY ELEC GEN 2/							
Customer Charge		1	74,727	897	99,615	1,195	33.3%
Demand Charge			3/	166,082		145,051	-12.7%
Volumetric Charg:							
Tier I	256,612		0.04469	11,468	0.04443	11,402	-0.6%
Tier II	1,130,478		0.01439	16,268	0.01376	15,558	-4.4%
TOT/AVE UEG	1,387,090		0.14038	194,71[illegible]	0.12487	173,206	-11.0%
COGENERATION							
Cogen NetofGC-2	329,750		0.13828	[illegible]5,598	0.12487	41,176	-9.7%
GC-2 Cogen	130,260		0.05197	6,770		7,024	3.7%
TOT/AVE COGEN	460,010		0.11384	52,368	0.10478	48,200	-8.0%
NONCORE SUBTOTAL							
Net of GC-2	3,122,160		0.13717	428,264	0.13525	422,261	-1.4%
Including GC-2	3,514,190		0.1276[illegible]	448,564	0.12615	443,321	-1.2%
WHOLESALE							
Demand Charges			3/	8,931		9,108	2.0%
Volumetric Charg	104,260		0.01040	1,084	0.01197	1,248	15.1%
TOT/AVE WHOLESALE	104,260		0.09606	10,015	0.09933	10,356	3.4%
TOT NONCORE							
Net of GC-2	3,226,420		0.13584	438,279	0.13409	432,617	-1.3%
Including GC-2	3,618,450		0.12673	458,579	0.12538	453,677	-1.1%

1/ Estimated billing determinants include UEG-SCE, steam heat, interdepartmental volumes.

2/ Revenue not based on existing tariff tiering.

3/ Customer charges for these schedules are tiered; demand charges for wholesale & UEG vary monthly.

4/ Revenues reflect exclusion of 49.4 MMTH from CPUC surcharge of $ .00076/therm.

(End of Appendix C)