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Decision 90-04-021 April 11, 1990

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 gas rates and tariffs effective April 1, 1990 in its Annual Cost Allocation Proceeding.	Application 89-08-024 (Filed August 15, 1989)

(Appearances are listed in Appendix A.)

I N D E X

O P I N I O N

I. Summary

This decision resolves issues raised in Pacific Gas and Electric Company's (PG&E) second Annual Cost Allocation Proceeding (ACAP). PG&E's bundled core rates will increase by 3.6%, or $61.5 million and its noncore transportation rates will decrease by 14.5% or $64.4 million.

This decision adopts an average oil price of $17.78/Bbl for purposes of making the core price forecast. The average spot gas price adopted is $2.35 per decatherm (Dth). The resulting core Weighted Average Cost of Gas (WACOG) is $2.14 and the noncore WACOG is $2.36/Dth. We adopt a throughput forecast of 7,652 million therm (MMth).

We follow the policy set forth in Southern California Gas Company's (SoCal) recent ACAP regarding equitable sharing of take-or-pay costs. We reject several rate design and cost allocation recommendations which more appropriately belong in proceedings we have recently instituted.

Finally, we order parties to participate in workshops headed by Commission Advisory and Compliance Division (CACD) to specifically address the discount adjustment calculation and more generally streamline the ACAP process.

II. Procedural Background

PG&E filed its application in the above-captioned proceeding on August 15, 1989, pursuant to the schedule set forth in Decision (D.) 89-01-040, the rulemaking which revised the time schedules for rate cases and fuel offset proceedings. This is the second ACAP which PG&E has filed since the Commission has restructured the gas industry in California. The test period at issue in this ACAP is April 1, 1990 through March 31, 1991. The ACAP is a forecasting proceeding, where the Commission sets rates for all customers that are based on an estimate of likely revenues at cost-based rates and also include an adjustment for a reasonable amount of discounting. Some discounting is expected, because many large customers have the market power to use cheaper options by purchasing oil, propane, or other alternative fuels.

In Application (A.) 89-08-024, PG&E requested authority to increase gas rates, as of April 1, 1990, by approximately $143 million over the gas rate level expected to be in effect as of January 1, 1990. PG&E states its proposed increase is attributable to a forecasted increase of $136 million in purchased gas costs, including amortization of prior-period gas cost undercollections, and a forecasted shortfall of $7 million in gas transportation revenues at present rates during the 12-month period ending March 31, 1991.

The first prehearing conference (PHC) was held on September 5, 1989. A schedule was adopted for completion of this ACAP proceeding including dates for the filing of motions to strike PG&E's prepared testimony. A second PHC was held on October 25, 1989 where the administrative law judge (ALJ) correctly ruled on the motions to strike PG&E's testimony, holding that the testimony in question, described as the ACAP simplification proposal, went beyond the scope of one utility's ACAP proceeding. In addition, the schedule previously set forth was altered slightly due to the earthquake in the San Francisco Bay Area on October 17, 1989. Prior to the commencement of hearings, the ALJ worked with PG&E and the California Industrial Group/California League of Food Processors (CIG/CLFP) to informally resolve discovery disputes between the two parties. In camera inspection of certain documents was undertaken by the ALJ to determine the relevancy of the documents to the ACAP proceeding. The parties agreed to be bound by the ALJ's rulings on these documents.

Hearings were held from November 20, 1989 through December 8, 1989. Witnesses testified for the following parties: PG&E, the Division of Ratepayer Advocates (DRA), CIG/CLFP, Salmon Resources Ltd. and Mock Resources, Inc. (Salmon/Mock), Canadian Producers Group (CPG), Federal Executive Agencies (FEA), and Toward Utility Rate Normalization (TURN). Seventy-two exhibits were received during hearings. In addition to opening and reply briefs filed by all of the parties who presented witnesses, the following parties also briefed certain issues: the Alberta Petroleum Marketing Commission (APMC), the California Cogeneration Council (CCC), SoCal, and Southern California Edison Company (SCE). In total, over 700 pages of briefs were received in this proceeding.

In addition, the ALJ ordered the preparation of a comparison exhibit in two parts. Part I of the comparison exhibit was received on December 19, 1989, and will be marked as Exhibit 73. Part II of the comparison exhibit shall be marked as Exhibit 74. Since no party has objected to the receipt of these exhibits in evidence, they shall be received at this time. This proceeding was officially submitted on January 23, 1990 with the filing of comments on the comparison exhibits.

Comments

Comments on the ALJ's proposed decision were filed by PG&E, TURN, Salmon/Mock, DRA, CPG, CCC, CIG/CLFP, and SoCal. Chevron USA, Inc. (Chevron) filed a Motion to Accept Late Filed Comments, which is hereby granted for good cause shown. In addition, Mojave Cogeneration Company, L.P. (Mojave) filed a Motion for Leave to Intervene and File Comments which is also granted.

All of these comments have been reviewed and carefully considered by the Commission. Any changes required by the comments have been incorporated in this decision.

III. Cost of Gas Forecast

Determining the appropriate forecast of the cost of gas for a utility in its ACAP proceeding is an important piece of the new gas industry structure. Under this new structure, the utility sells gas to its customers from either the core portfolio or the noncore portfolio. Core customers are served exclusively by the core portfolio which is comprised entirely of secure long-term supplies. Noncore customers can purchase gas from either the noncore portfolio, which is comprised largely of short-term gas, or the core portfolio. They also have the option of purchasing gas from someone other than the utility and transporting it over the utility system. Core ratepayers are indifferent as to whether or not noncore customers buy gas from the utility or someone else since the utility is required to sell the gas at cost. The utility's noncore margin (except UEG) is recovered entirely through the transportation rate.

In the ACAP, the Commission adopts an estimate of the WACOG for each portfolio. This estimate is then used to determine the revenue requirement. The WACOGs are also used as an input to the econometric models used to estimate throughput and the discount adjustment, both of which will be discussed in later sections of this decision.

In addition to adopting WACOGs for both the core and noncore portfolios, estimates for a number of other commodity-related costs such as storage injection and withdrawals and lost and unaccounted for (LUAF) gas must be adopted. Estimates for certain fixed costs such as pipeline demand charges, and commodity-related transition costs, are also adopted. Later in this decision, these fixed cost estimates will be flowed into cost allocation and spread to the different customer classes for recovery through rates. Each of these commodity-related cost estimates will be addressed in this section.

A. Introduction

First, we will turn to gas supply sources: Southwest, Canadian, California, and Rocky Mountain supplies. In addition to the debate over which party had formed a better forecast for each of the above supplies, the question of whether it would be more appropriate to use the "rates in effect" approach suggested by TURN was the subject of much debate, particularly in the parties' briefs.

B. Gas Supply Sources and Cost of Gas

1. Short-Term Southwest Supplies

a. PG&E's Position

PG&E forecasts its Southwest short-term or spot prices using three independent forecasting methodologies. PG&E alleges that these three methodologies yield similar results and chooses to average these results rather than rely on any single approach.

PG&E describes its first forecasting approach as an analysis of historical and postulated future relationships between: (1) spot gas prices at mainline entry points to the El Paso Natural Gas Company (El Paso) transmission system and (2) the U.S. Refiner's Average Acquisition Cost (RAAC) for crude oil between April 1986 and March 1989. Thus, PG&E attempts to project the Southwest spot price for the test period based on PG&E's proposed crude oil price and apparent historical oil/gas price relationships. This results in an El Paso mainline price for Southwest spot gas averaging $1.95/Dth for the test period.

PG&E's second approach is a simple trend analysis of spot gas prices at El Paso mainline entry points, based on actual monthly prices paid by PG&E from April 1986 to March 1989. From this approach, the resulting El Paso mainline price for Southwest spot gas averages $1.91/Dth for the test period.

The third approach utilized by PG&E employs the June 1989 DRI/McGraw-Hill forecast of well-head gas prices in the Permian and mid-continent areas, where most of PG&E's Southwest spot gas originates. Here, the resulting El Paso mainline price averages $1.93/Dth for the test period.

PG&E contends that on a volume-weighted basis, the three forecasting approaches result in an average Southwest mainline spot gas price forecast of $1.94/Dth for the test period at issue. PG&E alleges that transportation charges to move Southwest gas to the California border amount to $0.54/Dth, based on the El Paso transportation charges in effect as of August 15, 1989. Thus, PG&E concludes that the appropriate volume weighted Southwest spot gas price forecast at the California border for the test period is $2.48/Dth. Finally, PG&E concludes that a noncore WACOG based on the above analysis of $2.48/Dth should be adopted.

b. <u>DRA's Position</u>

In order to forecast the cost of spot gas from Southwest supplies, DRA employs a methodology making a straight-line projection of the prices at the California border (which include all transportation and other charges incurred to get the gas to the border). This projection, according to DRA, is based upon the actual historical California border prices from Natural Gas Week. DRA presented this approach in Exhibit 37, Figure 1-1. That figure depicts from its 12-month ended moving averages that the border price has been on a nearly straight trend since approximately the end of 1986. DRA chose to update this figure to include prices from September and October 1989 in Exhibit 38, which was presented for the first time at hearings. DRA's methodology is based on weighted averages of all customers in California and supplies from the three Southwest basins, based entirely on publicly available information.

In addition to adding two months' worth of data to its straight-line projection of the price of spot supplies at the California border, in Exhibit 38 DRA presented an additional methodology for the calculation of forecast gas prices, to confirm the visual projection. DRA justifies the inclusion of a new methodology at the time of hearing by pointing out that it stated its intention to do so in its original testimony Exhibit 37. DRA admits that the second methodology shown in Exhibit 38, the computer program calculation (the SMOOTH command in the TSP software) is not essential to DRA's case. However, relying on its updated information DRA projects a spot price of $2.33/Dth for this ACAP period. This translates, according to DRA, into a noncore WACOG of $2.34/Dth. It is important to note that the recommendations of Exhibit 37, the timely filed exhibit, are very similar. There, the forecasted average spot price is $2.35/Dth resulting in a noncore WACOG of $2.36/Dth.

DRA points out that PG&E used an entirely different methodology to arrive at its forecasted WACCGs. DRA claims that PG&E's method consisted of forecasting the mainline price (i.e., the price where the gas enters the transmission line), and then adding to this the cost of transportation, in order to arrive at the border price. DRA notes that this transportation cost is the current transportation (and other volumetric charges) cost of $0.54 on El Paso. DRA points out that PG&E assumes no future change in the transportation cost in its methodology, even though the PG&E witness admitted that these future charges are not presently known with certainty and that the surcharge could even decrease next spring.

DRA takes exception to PG&E's method of adding transportation cost in its methodology. DRA believes this methodology does not take into account the response of sellers of gas to changes in transportation costs. Instead, in DRA's view, the PG&E method assumes that mainline prices are in no way affected by or respond to the changes in transportation cost. DRA argues that PG&E is contending that when the transportation rate goes up because of an adjustment to El Paso's volumetric take-or-pay cost, there is no change in the mainline price. DRA believes that the record in this case demonstrates that this hypothesis is not true. DRA argues that because its forecast is based on a trend of historical data, variables such as weather, season, transportation cost, and others which determine supply and demand are already included. DRA asserts that the flaw in PG&E's case is that there are too many variables that may affect the cost of gas to simply assume, as PG&E did, that mainline prices do not respond to market conditions, and likewise, to assume instead that California border prices increase automatically in step with increases in transportation cost. DRA asserts its method is superior because it reflects all of the variables that affect the cost of gas by trending the cost of gas, based upon historical cost, which implicitly includes adjustments for all variables that cause price adjustments.

Further, DRA points out that its method forecasts the California border price, which is the price which ultimately goes into the WACOGs for use in the ACAP. Thus, by forecasting the California border price, DRA believes it need not forecast independently all variables that go into that price, since the historical basis of the trend includes these variables.

c. TURN's Position

TURN's primary recommendation with respect to gas price forecasting is that the Commission should refrain from doing any forecasting at all and instead base rates on current gas cost. Since TURN focuses its recommendation on its benefit in California and Canadian gas supply negotiations, it will be discussed in more detail in the Canadian supply section below. For purposes of Southwest supplies, TURN argues that the appropriate price for Southwest supplies should be $2.34/Dth.

d. Discussion

After sifting through the record on the forecast testimony for the short-term Southwest supply element of the cost of gas, we find TURN's "rates in effect" approach appealing. Coincidently, this approach results in a result very close to DRA's forecast. On the other hand, PG&E takes the approach that more forecasting is better, then averages the results of three different methodologies. PG&E's incentive, of course, is to forecast a higher WACOG which would ultimately result in a lower throughput. Thus, there would be a greater opportunity for PG&E to make a profit if in fact the actual throughput in the test period is higher than the forecast. Since all forecasting involves some amount of guesswork, DRA's approach of trending historical data is compelling. As set forth in DRA's Exhibit 37 this approach helps get away from the tendency for inflationary forecasting.

Unfortunately, rather than be content with the competent job it did in Exhibit 37, DRA seemingly felt compelled to update its material in Exhibit 38. Exhibit 38 appeared for the first time in the hearing room as the witness sponsoring it took the stand. In addition to updating two months of data, Exhibit 38 for the first time promoted a new methodology which DRA claims was to check its historical trending calculation. We note that the Exhibit 38 update results in an insignificant difference in the bottom line Southwest spot gas price and the resulting WACOGs. At some point, all parties must stop updating information or the record will be unmanageable. If PG&E had attempted such an updating, including a new "confirming" methodology, DRA would have had a legitimate complaint. The record is not served by such "on the stand" testimony. If some startling event had occurred to dramatically change the results of DRA's original numbers in Exhibit 37, such an update may have been helpful to the Commission's decision-making. However, in these circumstances, DRA's updated information in Exhibit 38 was merely a waste of valuable hearing time. However, the mistaken strategy call to put forward Exhibit 38 should not serve to reject the merits of DRA's otherwise reasonable approach embodied in Exhibit 37. We find DRA's approach more persuasive and frankly more straightforward than the average of the three forecasts propounded by PG&E. In addition, because the result is the same as TURN's "rates in effect" we believe this approach will not inflate gas-contract negotiations. Therefore, we will adopt, as found in DRA's original testimony in Exhibit 37, a forecasted average spot price for Southwest supplies of \$2.35/Dth resulting in noncore WACOG of \$2.36/Dth.

2. <u>Long-Term Southwest Supplies</u>

a. <u>PG&E's Position</u>

PG&E adds a \$0.05/Dth differential to the cost of long-term Southwest supplies in order to reflect the security of supply and take-level flexibility associated with these long-term supplies. Based on PG&E's short-term supply number this would result in a \$2.55/Dth cost for long-term Southwest gas during the test period. PG&E argues that this \$0.05/Dth premium is justified. PG&E points out that take level flexibility gives the buyer the unilateral right to vary the amount of gas taken, within negotiated limits, on a daily basis. PG&E argues that this flexibility offers buyers an opportunity to minimize their total gas cost by reducing purchases as needed in order to take advantage of less expensive supplies elsewhere. PG&E notes that both producers and buyers benefit from the price certainty and market security that longer term contracts provide. In PG&E's view, however, the allowance of take-level flexibility is uniquely of value to the buyer (PG&E) and a detriment to the seller, requiring additional compensation to the seller in the form of a higher price.

PG&E shows that on a simple average basis its long-term Southwest gas supply contracts are priced $0.05 above the spot gas market price. PG&E argues that this differential forecasted by PG&E in fact exists and should be recognized in the ratemaking process. PG&E maintains that since producers can and do command this differential under long-term contract where take-level flexibility is granted it should be reflected in the forecast.

b. DRA's Position

DRA objects to a $0.05/Dth premium above the spot price being included in the forecast. DRA argues that while it may be true that purchasers of contract gas obtained some benefits as a result of the contracting arrangement, producers of gas also benefit by the contracting arrangement.

According to DRA, supply contracts which include a fixed price protect the producer from price fluctuations, while at the same time ensuring that the producer would be able to sell his gas regardless of market conditions. DRA notes that PG&E acknowledges these benefits in its prefiled testimony. Further, DRA points out that PG&E acknowledges that during the one-year timeframe of the ACAP period, spot prices fluctuate both above and below prices in these contracts in certain months. DRA observes that during times when spot prices fall below the contract price, a producer obtains the benefit by being able to sell his gas above the spot market price while also enjoying the benefit of guaranteed minimum sale.

DRA emphasizes that while gas purchasers gain the additional security of known prices and dedicated supplies with take-level flexibility, they also sacrifice some flexibility under these contracts. Specifically, DRA points to the example that if the price of spot gas drops below the contract price, a purchaser such as PG&E is still obligated to purchase minimum take under the contract, even though it could obtain cheaper gas on the open market. Obviously, DRA asserts that such circumstances act as a constraint on the purchaser.

Since the benefits of the firm supply contracts flow both to the purchasers and the producers, DRA believes it is inappropriate to assume that the price of Southwest firm supplies will exceed the spot market price on average. DRA notes that these firm supply contracts are negotiated by PG&E in a competitive market environment. DRA asserts that adoption by this Commission of a forecast that sets the price of firm supply gas $0.05/Dth above the price of spot gas will ensure that producers will have this price adder as part of their bottom line negotiating position for firm supply contracts. DRA believes that the adoption of such an adder will distort and restrict PG&E's ability to obtain a lower price in negotiations. DRA points out that the cost of these firm supplies is protected by the core WACOG balancing account in any event. Given this, DRA believes the Commission should adopt a conservative forecast which maximizes PG&E's negotiation flexibility, rather than a forecast that virtually guarantees higher gas cost. Thus, DRA recommends that the Commission adopt the same price for Southwest firm supplies as it adopts for spot gas.

c. Discussion

We concur with DRA's analysis that the benefits of these long-term supply contracts flow to both producers and purchasers. That being the case, we view the $0.05/Dth premium as a give away to the producers. Both producers and purchasers gain something by entering into this contract. Since the benefits flow both ways it does not seem reasonable to expect a premium to be paid. Once again, by forecasting such a premium we would run the danger of a "self-fulfilling prophecy" in PG&E's negotiation with gas producers in the Southwest. For these reasons, we will adopt the same price for Southwest firm supplies as we adopted for spot gas above, namely, $2.35/Dth.

3. <u>Canadian Supplies</u>

a. <u>PG&E's Position</u>

PG&E forecasts the Pacific Gas Transmission Company (PGT)/Canadian price to average $2.04/Dth (wet) at the U.S./Canadian border for the test period. PG&E bases this price on the assumption that the current Canadian price of $1.90/Dth (wet) will remain in place until June 1990, then increase in July 1990 for the rest of the test period, to $2.10/Dth (wet), consistent with the $0.20/Dth increase forecasted for Southwest supplies. PG&E forecasts for the test period an average price of $2.07 at the California border when converted from wet to dry and when other charges are included.

PG&E argues that Southwest supply prices are viewed as a significant pricing factor by Canadian and California producers. PG&E points out that gas supply from the Southwest into California is 3.6 billion cubic feet per day (Bcf/day) while California and Canadian supplies combined provide only 1.5 Bcf/day due to limited capacity on the PGT system and limited availability of California supplies. In PG&E's view, given the predominance of Southwest gas supplies in determining the market price for gas in California, PG&E used its projected commodity price for long-term Southwest gas as the primary indicator of both the direction and magnitude of changes and commodity prices for gas supplies from Canada, California, and the Rocky Mountains.

PG&E argues that the link between Canadian prices and Southwest prices is particularly strong. PG&E points to the gas sale contract between Alberta and Southern Gas Company (a PG&E affiliate) and PGT which provides for review and, if appropriate, revision of the stated commodity rate based on competitive conditions in the PG&E market. PG&E points to the participation of Canadian producers in this proceeding as evidence that those producers closely watch conditions in the PG&E market and are aware of the impact of Southwest gas prices. Therefore, since PG&E

forecasted a $0.20/Dth increase in Southwest prices for the test period, it has forecasted an equivalent increase in the Canadian price for the test period.

In defense of its position, PG&E points out that no other party performed a quantitative analysis that shows that Canadian prices will remain unchanged during the test period. PG&E believes that the simple fact that negotiations for Canadian prices are not scheduled to occur until the spring is no reason to penalize PG&E by not including an increase in price in the ACAP forecast. PG&E argues that its stated intention and traditional practice is to bargain aggressively with natural gas suppliers to obtain the lowest possible prices. Therefore, there is no danger in including a $0.20/Dth price increase for Canadian supplies in the forecast.

b. <u>DRA's Position</u>

DRA recommends that no increase in the price of gas from Canada be included in the ACAP forecast. DRA points out that PG&E's recommendation is predicated on the adoption of a $0.20/Dth increase in its Southwest long-term supply prices. DRA argues that forecasting a price increase of Canadian gas before the contract negotiations occur could likely have a detrimental effect on the negotiating process. The danger of the self-fulfilling prophecy is evident. DRA concurs with the concerns raised by TURN, which will be discussed below. Further, DRA points out that since it believes PG&E's long-term Southwest prices too high, Canadian prices should not be tied to them. Further, given the fact that future fixed costs on both El Paso and PGT are unknown at this time, DRA argues it is not at all clear that the incremental price of Canadian gas has to increase, even if Southwest prices were to increase.

c. <u>TURN's Position</u>

As discussed briefly above in the section on short-term Southwest supplies, TURN has recommended that the Commission abandon any attempt to forecast gas prices and instead rely on "rates in effect." As TURN witness Florio succinctly testified:

> "I seriously question whether it is a wise policy for PG&E and the Commission itself to attempt to forecast in an ACAP application the future level of prices under gas purchase agreements that may be under negotiation at the very same time. This concern is particularly strong with respect to PG&E's purchases of California and PGT/Canadian gas, since those producers actively monitor the Commission's proceedings and can use information garnered there as bargaining leverage against the utility. The very act of promulgating a forecast may influence the perceptions of suppliers preparing to negotiate with PG&E. If the utility says openly that it expects to pay 20¢ per million Btu more for its long-term gas supplies why should any potential supplier disagree or act inconsistent with that perception?" (Exhibit 51, pp. 12-13.)

TURN points out the danger that the ACAP proceeding could ultimately disadvantage PG&E's procurement efforts in a manner detrimental to its customers' best interests. TURN recommends an alternative approach that could avoid this pitfall. TURN urges the use of a "rate in effect approach" that was used under the prior gas adjustment clause (GAC) procedure where PG&E did not forecast its gas costs per se. TURN quotes the preliminary statement of PG&E's former GAC tariff which provided as follows:

> "<u>Current cost of purchased gas</u> The current cost of purchased gas by the utility under each supplier rate schedule and contract shall be determined by application of the rates in effect on or before the date of filing to the current period volume of gas purchased under each such supplier rate schedule and contract. However, if an

> interstate supplier has filed with the Federal Energy Regulatory Commission a higher or lower rate which will become effective on or before the revision date, the utility may apply this rate." (Opening brief of TURN, p. 29.)

TURN is worried that the forecasting approach potentially sends the wrong signals to suppliers with whom the utility may have to negotiate. TURN believes that the figure in the forecast could easily become the price floor in negotiations. Further, TURN points to the record in this proceeding as providing ample evidence of the tendency for parties to use ACAP price forecast as a preliminary bargaining tool for price renegotiation.

TURN's annual gas rate (AGR) proposal which was included as a second alternative to its rate in effect proposal will be discussed in Section IX of this decision. Thus, TURN's primary recommendation is adoption of a price of about $1.93/Dth for PGT/Canadian gas.

d. Other Parties' Positions on TURN's "Rates in Effect" Proposal

Both DRA and CPG support the principle behind TURN's rates in effect proposal.

CPG argues that the issue essentially boils down to a question of whether projections of gas costs can be accurate enough, as a product of a contentious hearing process based on a wide range of individual parties' forecasts, that the benefits gained from their use in determining rates more than offset the costs of the controversy they arouse and the misleading or improper market signals they send. CPG believes that TURN's rates in effect proposal would achieve the benefit of truly simplifying the ACAP process, without injury to the utility over the longer term. CPG argues that while PG&E worries that the use of current gas costs will penalize it in a rising market, PG&E is ignoring the equal likelihood of future market softness, with consequent rate benefits to the utility. Further, CPG believes that the end result of gas cost forecasting controversies in ACAPs is likely to be very close to the "rates in effect". CPG notes that PG&E already has strong incentives to overestimate future gas costs in ACAP cases; while customers and suppliers have exactly the opposite motivation. Finally, CPG points out that this was the method that the Commission used in PG&E's first ACAP case, D.89-05-073.

DRA's support for a "rates in effect" approach to Canadian supplies, or no price increase, has already been discussed in Section b. above.

Salmon/Mock and PG&E strenuously object to TURN's "rates in effect" proposal.

Salmon/Mock argues that TURN's "rates in effect" proposal represents a head-in-the-sand approach to gas price forecasting. Salmon/Mock believes the adoption of a method that relies exclusively upon existing prices ignores recent and projected developments in the gas market. Salmon/Mock asserts the use of existing prices guarantees an outdated portfolio WACOG forecast, resulting in a core portfolio price that is not reflective of market conditions. Salmon/Mock also notes that TURN's reference to the old GAC procedure is inappropriate because PG&E was not directly at risk for the recovery of noncore revenues. Under the new regulatory structure, Salmon/Mock maintains that PG&E is directly at risk and the gas price forecast is an important component of the risk determination. Salmon/Mock argues that the forecast of gas prices should be based upon the best information available to the Commission concerning what the gas prices would be during the ACAP period. While Salmon/Mock acknowledges that existing gas prices are relevant to this forecast, they do not believe existing prices should be the only determinants of the new forecast.

PG&E argues that TURN's "rates in effect" proposal, while appearing reasonable on its face, results in lowering of gas prices which are key variables in the calculation of throughput and the discount adjustment factor. PG&E contends that this intentional underestimation will deprive PG&E of a reasonable opportunity to recover its authorized rate of return. PG&E asserts that if there is any reason to expect that actual gas costs during the test period will be higher than the existing gas costs, then the use of existing gas costs for the purpose of calculating the level of throughput to be used for cost allocation purposes would overstate throughput generally and understate the amount of discounting required during the test period resulting in an unavoidable overallocation of cost to the noncore. PG&E asserts that any such intentional overallocation of cost to the noncore would result in an automatic and certain loss to PG&E shareholders. PG&E maintains that such a result would reflect unlawful and unprincipled ratemaking policy.

PG&E points out that the use of an inaccurate gas price forecast in setting rates has a direct effect on PG&E's ability to recover costs allocated to the noncore class. If the gas price forecast is too low, the discount adjustment calculation shows less discounting than will really be required. PG&E disagrees with TURN's concern that a forecasted increase in the Canadian price in this proceeding will weaken PG&E's bargaining position in the upcoming Canadian price redetermination discussions. PG&E disputes that it has any obligation to offer Canadian producers the price forecasted in this proceeding. Once again it states its intention and practice of bargaining aggressively with natural gas suppliers to obtain the lowest possible price while balancing other objectives such as supply reliability and price stability. PG&E submits that on the basis of the record in this case there is no reasonable basis for assuming the gas prices will remain constant or decline during the test period. Therefore, PG&E argues that adoption of the DRA/TURN proposal to hold the Canadian price constant for the test period would be unreasonable and confiscatory.

e. <u>Discussion</u>

The "rates in effect" proposal has particular appeal in forecasting the Canadian price. The Canadian supply situation is more disconcerting in that we are faced with the situation where we know negotiations for new prices will begin very shortly. The attractiveness of not sending a message that this Commission approves a price increase of 20¢ is obvious. In fact, our overriding desire is to remain neutral on the subject of whether Canadian prices should increase or decrease and truly allow PG&E an opportunity to negotiate aggressively without giving its producers a signal that California is expecting a price increase of a certain amount.

After the submission of this proceeding, the Federal Energy Regulatory Commission (FERC) issued an order in Pacific Gas Transmission Company Inc.'s (PGT) General Rate Case (Docket RP 87-62-000 and RP 86-148-000, issued January 24, 1990). This decision will certainly impact the price PG&E pays for Canadian gas during the ACAP forecast period. Thus, while we agree in principle with the "rates in effect" proposal, the "rate in effect" price of $1.90/Dth as propounded by TURN and DRA at hearing is too low in light of this recent FERC order. In fact, in light of events after submission, PG&E's forecast of $2.07/Dth for Canadian supplies is essentially an updated "rates in effect" approach. Our endorsement of the "rates in effect" proposal is not meant to be punitive and should reflect the most recent information, e.g., the January 24, 1990 FERC order, available to us. We will follow with interest what the upcoming negotiations result in to determine if this approach has any impact on that process. We expect PG&E to be vigilant in negotiating with the Canadian producers. We want the Canadian producers to absorb some of the increased costs if they occur, rather than all being passed on to California ratepayers. Therefore, we will adopt a price of $2.07/Dth for Canadian supplies, but this should not be assumed to be a floor price. We leave open to PG&E the opportunity to better this price in upcoming negotiations.

4. California Supplies

a. PG&E's Position

For this ACAP test period PG&E forecasts that the California gas price will average $2.03/Dth. PG&E bases this forecast on an assumption that the current $1.85/Dth will continue through April, 1990, and a price increase to $2.05/Dth will occur as of May 1, 1990. PG&E believes that this price is consistent with the 20¢/Dth increase forecasted for Southwest supplies. PG&E notes that no intervenor has opposed PG&E's California volume forecast of 92,323 MDth for the test period.

PG&E points out that in addition to the historical price movement relationships between California and Southwest prices, other market factors suggest that the California gas price will increase during the test period. PG&E points out that the availability of third-party transportation in California, combined with the recent elimination of the California gathering charge by D.89-04-089, results in greater competition for California gas from gas purchasers other than PG&E. PG&E asserts that this new competition for California gas supplies will tend to increase the California gas supply price.

PG&E contends that California gas availability to the utility is decreasing because gas is being sold by producers directly to end users. Due to higher commodity prices for Southwest supplies relative to California supplies, high demand for gas in the Southern California market and limited available capacity to obtain Southwest supply, PG&E asserts that some Northern California producers are selling gas to customers located in Southern California at prices above PG&E's current $1.85/Dth price. PG&E argues that if it wishes to retain access to this supply for its core customers, it will need to offer a price above the current $1.85/Dth in order to compete with these other gas purchasers. PG&E points out that neither DRA nor TURN has done any quantitative analysis of California gas prices, arguing that their position of no price increase lacks any real coherence. Thus, PG&E requests that the Commission adopt a California gas test period forecast of $2.03/Dth.

b. Other Parties' Positions

Both TURN and DRA once again argue that the current price be used for the forecast period for California gas. That price would be $1.85/Dth.

DRA argues that PG&E did not include the effects of the Commission's recent decision regarding the cost of gathering of California gas in its forecast for the price of California gas. DRA cites D.89-12-016 whereby the Commission reduced the gathering adjustment to California producers by 12¢, reducing from 34¢ to 22¢. The effect of this is to increase the net back to California producers, i.e., it increases the amount that they receive for their gas. DRA asserts that given these circumstances in the next round of California gas price negotiations, California prices should not be determined solely with reference to any increases experienced in Southwest gas prices. As with the Canadian supplies, DRA believes there is legitimate justification for treating the forecast differently than it did for Southwest spot gas prices.

TURN maintains its consistency in once again arguing for a "rates in effect" approach to the California gas supply. Likewise, CPG includes California supplies in its observation that "rates in effect" would have some benefits to the negotiation process.

c. Discussion

We are persuaded by DRA's and TURN's position regarding California supplies. Our reasoning is similar to that expressed in the discussion on Canadian supplies. It is not our intention to be punitive by not predicting a price increase. We hope to send a clear signal to the California market that our goal is to allow PG&E to negotiate aggressively to obtain the lowest possible prices for its end users. Similar to the situation with the Canadian gas price, our recent gas gathering decision allows current contract prices to increase. Thus PG&E's $2.03/Dth is closer to a realistic "rates in effect" approach. Therefore, we will adopt a price of $2.03/Dth for California gas. We stress we expect PG&E to negotiate aggressively with California producers. Finally, we will adopt PG&E's volume forecast of 92,323 MDth since there was no opposition to this figure.

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

a. <u>PG&E's Position</u>

PG&E forecasts that the Rocky Mountain price will average $1.95/Dth at the California border during the test period. PG&E bases this forecast on the assumption that the current $1.25/Dth well-head price will remain in effect through June 30, 1990, and will increase to $1.45/Dth in July of 1990 for the balance of the test period, consistent with the 20¢ increase forecasted for Southwest supplies. PG&E's volume forecast is 2,589 MDth for the ACAP period.

b. <u>Other Parties' Positions</u>

DRA adopted PG&E's Rocky Mountain price forecast for the test period. DRA's reason to do so, even though it is somewhat inconsistent with its position on Canadian, California, and Southwest supplies, is because the volume and price of Rocky Mountain gas have a minimal effect on the core WACOG.

TURN consistently recommends that the Rocky Mountain price be held to the existing rate. TURN witness Florio recommends that this rate should be about $1.75/Dth.

c. <u>Discussion</u>

This issue received little attention from the parties in testimony, hearings, or briefs. PG&E makes much of the fact DRA is inconsistent in its adoption of PG&E's forecast in this area while adopting a "rates in effect" position for California and Canadian gas. It is clear from DRA's brief that since the stake involved in this item was small, DRA chose not to contest an issue that had little impact on the bottom line core WACOG. Therefore, we will adopt the PG&E's price of $1.95/Dth at the California border and its volume forecast of 2,589 MDth for the test period. However, we do not find this supply source to be significant enough for it to undermine our rationale for selecting a "rates in effect" approach for other supply sources as we have done above. If PG&E makes much of the so-called inconsistency in its comments on the ALJ proposed decision, we may succumb to the temptation to lower the Rocky Mountain price in order to be consistent with our "rates in effect" approach.

C. <u>Canadian and Southwest Supply Volumes</u>

a. <u>PG&E's Position</u>

PG&E proposes equivalent percentage sequencing between Canadian and Southwest supplies beginning in July of 1990. PG&E asserts that the resulting Canadian and Southwest volume forecasts for the test period are 295,015 MDth and 157,967 MDth, respectively. PG&E asserts that its sequencing policy is to purchase gas supplies on a least cost basis, subject to operating and contractual requirements. PG&E states that in order to meet core portfolio demands, it currently purchases all available California and Rocky Mountain gas due to their competitive prices. Next, PG&E purchases other long-term supplies, such as PGT/Canadian and Southwest gas. Under certain circumstances, PG&E states it may use short-term supplies to serve the core portfolio. PG&E uses short-term Southwest supplies to meet the noncore portfolio demands.

For April through June 1990 (the first three months of the ACAP test period) Canadian gas is assumed to be sequenced preferentially vis-a-vis Southwest supplies due to its competitive price. PG&E makes an exception for those Southwest supplies needed to serve demand located in the southern portion of PG&E's system. After June 1990, Canadian and Southwest supplies are forecasted by PG&E to be priced competitively with each other on an average cost basis. PG&E asserts that the purpose of average cost sequencing is to equalize the difference between pipeline rate design. PG&E argues that if an incremental cost comparison were made between

Canadian and Southwest supplies, Southwest supplies would be unfairly disadvantaged.

PG&E relies on the testimony of its witness Seedall for the proposition that the average cost of Canadian and Southwest supplies are forecasted to be within 10¢/Dth of each other. PG&E points to D.84-12-067 where it claims the Commission concluded that equivalent take sequencing is appropriate for supply prices which are within 10¢/Dth of each other. This is PG&E's rationale for assuming that supplies are to be sequenced on an equivalent basis starting in July 1990.

PG&E points out that in its last ACAP, the Commission adopted a sequence which had Canadian supplies at maximum availability while supplies on the southern portion of PG&E's system were considerably below operational needs. PG&E asserts that this decision resulted in forecasted supply takes that differed from historical levels. As a result, in PG&E's view, the portfolio construction adopted by the Commission in its last ACAP resulted in significant gas cost undercollection in the core gas cost balancing account, since greater levels of higher cost Southwest supply had to be taken than to meet operating needs.

In its brief, PG&E states that DRA does not challenge its gas supply sequencing proposal.

b. <u>DRA's Position</u>

On the other hand, DRA states in its brief that PG&E has "misstated" DRA's position with regard to PG&E's gas supply sequencing proposal. DRA argues that its position is entirely neutral. DRA claims that it neither opposes nor supports the proposal. DRA maintains that PG&E's sequencing decisions, whatever they are during the forecast period, should be subject to review in a reasonableness proceeding. DRA argues that the reasonableness review proceeding is the appropriate forum to judge PG&E's sequencing decisions based upon the circumstances during the relevant time period. DRA acknowledges that because gas prices could vary from the forecasts adopted in this proceeding, PG&E should retain flexibility in its sequencing decision-making process.

c. Other Parties' Positions

CPG, CIG/CLFP, Salmon/Mock, and TURN all express some concerns with PG&E's proposal to move towards equivalent percentage sequencing between Canadian and Southwest gas supplies. CPG, CIG/CLFP, and Salmon/Mock all believe that PG&E has underestimated its throughput forecast on the PGT/Canadian pipeline. In addition, CPG asserts that PG&E has seriously underestimated Southwest gas costs in determining that equivalent as opposed to preferential sequencing may be in the better interests of PG&E's ratepayers.

CPG argues that PG&E manipulated the factors to develop its position that equivalent percentage sequencing would be a good move to make after June 1990. CPG argues that PG&E omitted direct billed take-or-pay costs that are due to El Paso gas pipeline purchases, understated the current volumetric portion of the take-or-pay amounts, used overly generous El Paso pipeline capacity and unduly minimized PGT pipeline capacity on an average basis in the equation.

Salmon/Mock and CIG/CLFP both argue that PG&E has underestimated its capacity on the PGT pipeline by some 200 MMcf/day. Salmon/Mock goes on to recommend that a mandatory level of transportation only gas should be forecasted for that amount over the PGT pipeline. Salmon/Mock points out that PG&E witness Seedall testified that available capacity on the PGT pipeline during the forecast period was 1,017 MMcf/day. However, Seedall then testified that PG&E forecasts approximately 800 MMcf/day of gas supplies over the PGT pipeline. Salmon/Mock believes this to be unreasonable and recommends that the full capacity be used. Salmon/Mock cites D.89-05-073, the Commission's last PG&E ACAP decision, in which a forecast of 1,009 MMcf/day of Canadian gas purchases by PG&E was made for the 1989 ACAP period.

TURN states in its reply brief that if PG&E does not preferentially sequence Canadian gas, then any spare capacity which would become available on the PGT system should be assumed to be used to provide on system or interutility transportation. TURN asserts that PG&E should not be allowed to maintain PGT in enforced idleness when its capacity is not required to provide core service.

d. Discussion

While the issue of the PGT/Canadian pipeline capacity was the subject of much cross-examination during the hearing, we believe more time was spent on it than the issue warranted. We agree with DRA that the issue of whether PG&E chooses to follow equivalent or preferential percentage sequencing is one that will be looked at in a future reasonableness review. Likewise, we do not find compelling the arguments that the volume forecast for the PGT line should be increased. Salmon/Mock's proposal that a certain amount of capacity on the PGT system should be set aside for transport only customers is irrelevant to an ACAP proceeding. The ACAP is not pipeline specific but source specific in its forecast of gas supplies. Further, we find merit in PG&E's argument that Salmon/Mock's and other parties' proposal to make PG&E accountable for unused capacity on PGT ignores the operating realities faced by PG&E. PG&E is accountable for its gas purchases and volumes in its reasonableness review and Salmon/Mock should make their case there. We have consistently refused to do more than provide broad policy guidelines for utility gas purchases. Our goal regarding core gas procurement has been for the utility to construct a portfolio which reasonably results in certainty of supply availability to serve core peak requirements. We expect the utility to attain this objective at lowest possible cost. PG&E points out that it is unable to use the PGT pipeline to its maximum available capacity on a day-to-day basis due to a combination of forecast uncertainty, sudden demand changes, limited storage cycle capability, and El Paso's 48-hour nomination rule. Thus, the recorded variation in PG&E's daily demands is significant. We agree with PG&E that, as a result, on some days the PGT pipeline may not be full.

Of course, we encourage PG&E to make available unneeded capacity for transport only customers on the PGT system, but doing this must be in keeping with PG&E's first priority to operate its gas system for the benefit of PG&E's core customers. Because we adopt a sales forecast higher than PG&E's, we will adjust PG&E's Canadian and Southwest volumes upward equally. In conclusion, we adopt a volume forecast of 162,976 MDth for Southwest supplies and 300,024 MDth for Canadian supplies.

D. Pipeline Demand Charges

PG&E and DRA are in agreement on the $177.778 million stated by PG&E in this ACAP period for (1) the demand charge for Canadian gas, (2) the PG&E cost of service charge, and (3) the El Paso demand charge. No other party to this proceeding disputes this. Therefore, we will adopt the agreed-upon figure.

E. Transition Costs

Transition costs are defined as costs resulting from gas purchase contracts, tariffs, or arrangements that: (1) took effect before the division of the supply portfolio into core and noncore in the December 1986 Commission decisions; (2) were initiated for the benefit of all ratepayers; (3) were intended to be recouped from all ratepayers; and (4) now result in costs in excess of a currently reasonable level (D.87-12-039, p. 118).

1. Storage-Related

Since DRA accepts PG&E's estimates that monthly storage-related transition costs which according to D.87-12-039 were to be subtracted from the cost of gas, will be zero in this ACAP period, we concur with that finding.

2. Liquids Settlement

PG&E estimates liquids settlement direct bills to total $6.8 million for the test period. This direct bill will end June 30, 1990 (PG&E's Exhibit 1). PG&E notes that the Commission treated this cost as a transition cost in D.87-12-039 and approved its recovery in PG&E's rates. DRA accepts this amount, breaking it down to $2,278,866 as PG&E's share for each of the first three months of the ACAP period (April through June 1990). This being the case, we too will accept this amount.

3. El Paso's Account No. 191 and Offsetting Revenues

a. PG&E's Position

PG&E seeks recovery in this ACAP proceeding of $18.6 million in El Paso's Account No. 191 direct bill costs. PG&E argues that Account No. 191 direct bill costs are properly categorized as transition costs pursuant to D.87-12-039. Account No. 191 costs were incurred by El Paso because of differences between actual and forecasted gas costs. PG&E claims the costs relate to gas supply contracts and tariff provisions in effect prior to the December 1986 Commission decisions instituting the gas industry restructuring in California. PG&E asserts that the gas sales agreement between PG&E and El Paso was entered into for the benefit of all PG&E's customers. PG&E points out that the Account No. 191 mechanism relates to the old gas industry structure. PG&E argues that since all customers have benefitted from the new industry structure, it is appropriate the costs associated with implementing this new structure be collected from all customers.

PG&E asserts that El Paso's Account No. 191 expenses are very similar to another transition cost that was recorded in El Paso's Account No. 191 and that was given balancing account treatment by this Commission: namely, expenses associated with the El Paso liquids settlement.

PG&E proposes that these costs be recovered through PG&E's core gas fixed cost account (GFCA) and noncore transition cost account (Exhibit 1).

PG&E has received certain "transition cost offsets" from El Paso in connection with two unrelated Federal Energy Regulatory Commission (FERC) proceedings. They propose to use these to offset not only Account No. 191 costs, but also take-or-pay direct bills and El Paso liquid expenses.

The first offset is a payment of $29.6 million which PG&E received as a partial settlement in the Tenngasco et al. v Southland Royalty Company (FERC Docket No. CI 85-513). According to PG&E, the Southland settlement would reduce its estimated total transition costs in the ACAP period from $90.2 million to $60.6 million.

The second offset is a $16 million payment, plus interest, received in December 1989, as part of the Chevron settlement. Currently, both of these amounts are accruing interest in a deferred credit account. The Southland and Chevron payments total approximately $48 million.

PG&E proposes that a $19.8 million payment from El Paso for claimed excess deferred income tax expense not be included as an offset until the appeals process is exhausted.

Finally, PG&E notes that if the Commission defers putting Account No. 191 costs into rates, the Commission should explicitly authorize eventual recovery.

b. DRA's Position

DRA estimates the Account No. 191 costs, as adjusted by anticipated offsetting revenues, to be approximately $6 million for this ACAP test period. DRA recommends that these Account No. 191 amounts not be included in rates for this ACAP period, but instead be tracked for recovery, with interest and recovered in the next ACAP period. DRA cites the pending legal challenges to the amounts in this account as a reason to postpone including these amounts in rates.

c. CIG/CLFP's Position

CIG/CLFP objects to the treatment of Account No. 191 costs as transition costs at all. CIG/CLFP views the Account No. 191 amounts as unrecovered purchased gas costs that do not meet the Commission's definition of transition costs as laid out in D.87-12-039.

First, CIG/CLFP asserts that no evidence supports PG&E's assertion that these costs relate to gas supply contracts and tariff provisions in effect prior to December 1986. CIG/CLFP points out that the costs at issue relate to differences between El Paso's actual and forecasted gas supply costs. CIG/CLFP cites PG&E witness Seedall for the proposition that he did not know whether the costs El Paso booked to Account No. 191 result from pre-1986 contracts between El Paso and its suppliers. CIG/CLFP asserts that the date of PG&E's contract with El Paso is irrelevant to the question of whether these costs qualify as transition costs under the Commission's four-part test laid out in D.87-12-039.

Second, CIG/CLFP argues that because these are unrecovered purchased gas costs, they necessarily were incurred for the benefit of PG&E sales customers only, not for the benefit of all PG&E customers. CIG/CLFP maintains that had El Paso's forecast of gas costs been more accurate, these costs would have been reflected in its contemporaneous commodity rates and paid for solely by sales customers.

Finally, CIG/CLFP argues that the idea that these costs are associated with the implementation of the new gas industry structure elevates form over substance. CIG/CLFP asserts that simply because FERC has authorized El Paso to directly bill these accounts to its sales customers (instead of requiring that they be recovered through commodity rates) does not magically transform them into a cost associated with the new gas industry structure.

For these reasons, CIG/CLFP objects to PG&E's attempt to have noncore ratepayers subsidize these costs attributable to PG&E's core portfolio purchases. However, if the Commission decides to defer recovery of these costs as DRA proposes, then CIG/CLFP has no objection to the Commission likewise deferring a decision on whether to afford "transition cost" treatment to Account No. 191.

d. Discussion

We will apply the Southland and Chevron settlements as offsets in today's decision which total approximately $48 million, including interest. We agree with PG&E that the El Paso deferred tax payment should be not be used as an offset at this time. Further, since submission of this case, the U.S. Court of Appeals issued a decision in that case which will require PG&E to return the $19.8 million deferred income tax amount to El Paso (Public Utilities Commission of the State of California v FERC (Case No. 88-1530, DC Circuit)).

We concur with DRA's position that it seems reasonable to defer ratemaking treatment for the Account No. 191 amounts at this time. Instead, we will order that they be tracked for recovery, in memorandum accounts, with interest and recovered if found to be appropriate in the next ACAP period. Likewise, we agree with CIG/CLFP's argument that the issue of whether recovery should ultimately occur of these amounts should likewise be deferred to the next ACAP period. We believe CIG/CLFP has raised some interesting arguments as to whether these are properly "transition costs" under Commission definitions. However, we need not reach a decision on that issue today. We disagree with PG&E that it is appropriate to explicitly authorize recovery of the Account No. 191 costs at this time.

F. <u>Storage Costs</u>

DRA accepts the PG&E forecast of inventory conditions at the beginning of the ACAP period which is $2.12/Dth with the forecasted volume of 65,857 MDth. However, DRA calculates the monthly carrying costs to be a total of $14.163 million for the ACAP period, using the one-month commercial paper rate and the DRA forecast of gas prices. PG&E forecasts an amount of $16.607 million for the carrying cost based on its forecasted gas prices and the June 1989 Bankers' Acceptance Rate. DRA has examined the monthly volumes forecasted by PG&E for withdrawal and injection and finds them similar to previous years.

We will adopt a forecast of carrying costs of $14.095 million based on DRA's method and the gas prices adopted herein.

G. <u>Allocation of Take-or-Pay Costs</u>

1. <u>Overview</u>

In January 1990, the Commission issued D.90-01-015 in SoCal ACAP proceeding, which extensively discussed the background and appropriate resolution of the take-or-pay allocation issue (D.90-01-015, pp. 44-60). In light of that recent decision, we will not spend a great deal of time on this issue, particularly background information, in this decision. Briefly, direct-billed take-or-pay costs are amounts billed to PG&E by El Paso to recover payments made to gas producers as consideration for waiving, revising, or amending the take-or-pay minimum payment provisions of a contract. These take-or-pay costs result from contracts between pipelines and producers. Neither PG&E nor any of its customers were parties to those contracts. As we did in D.90-01-015 we take official notice of FERC Order No. 436 and Order No. 500.

The arguments of the parties on take-or-pay cost allocation are virtually the same as those raised in the SoCal ACAP. The parties argued this issue at length in their briefs. The only changed circumstance is that some parties are arguing for a postponement of a decision on ratemaking treatment for direct-billed take-or-pay costs because of a recent decision of the U.S. Court of Appeals for the District of Columbia Associated Gas Distributors v FERC, No. 88-1385, decided December 28, 1989. (AGD decision.)

The AGD decision concludes that a FERC regulation requiring the allocation of the direct-billed portion of take-or-pay expenses on the basis of purchase deficiencies violates the filed rate doctrine.

2. Parties' Positions

PG&E and DRA agree on the amount of take-or-pay costs at issue in this case, namely, $64.8 million. This consists of $35.2 million expected to be incurred for the forecast period and $29.6 million for the pre-April 1990 period. However, PG&E and DRA disagree on how much of the take-or-pay obligation should be borne by PG&E's ratepayers.

PG&E is opposed to the adoption of any method that places its shareholders at risk for these costs, or requires them to absorb some portion of them. PG&E seeks to recover all directly billed take-or-pay costs through demand charges with balancing account treatment. PG&E sets forth the same legal arguments that it made in the SoCal ACAP.

The allocation method recommended by DRA is the same method it proposed in SoCal ACAP and which was adopted by the Commission. DRA recommends a method that is similar to the equitable sharing mechanism provided for by the FERC in its Order No. 500. Under the DRA proposal, PG&E would have the option of choosing between two methods of recovery. The methods would be: (1) recovery of all take-or-pay costs through a volumetric surcharge without balancing account protection; or (2) recovery, through a demand charge, of four times the percentage of direct-billed take-or-pay costs that the company agrees to absorb. Under this second option, any balance remaining above direct-billed and absorbed amounts would be recoverable through a volumetric charge. DRA proposes balancing account treatment for the portion allocated to the demand charge.

In its reply brief, DRA addresses the AGD decision and the argument of CIG/CLFP and TURN that the Commission should defer ratemaking treatment for any take-or-pay costs at this time. While DRA acknowledges that the AGD decision casts doubt on the future status of PG&E's take-or-pay costs, DRA nonetheless believes they should be put into rates for this ACAP period. DRA points out that, like SoCal, PG&E is already paying these costs. For consistency's sake, DRA believes the same equitable sharing mechanism should be adopted for PG&E with the caveat that the collection of these take-or-pay costs should be made subject to refund. Thus, if PG&E is ultimately refunded all or part of the take-or-pay costs it has paid, then the amount PG&E has overcollected from ratepayers could be refunded.

PG&E is likewise opposed to postponing ratemaking treatment in light of the AGD case. PG&E points out that delay in passing these costs to ratepayers, while continuing to accumulate these costs in an interest-bearing deferred debit account, will only result in even greater costs to be passed on later.

As did the other parties, Salmon/Mock and CIG/CLFP argue the same position they did in the SoCal ACAP, namely that PG&E's shareholders should absorb all of the direct-billed take-or-pay costs.

Finally, TURN notes that the debate over the ratemaking treatment of direct-billed take-or-pay costs was "essentially a complete rerun of the same issue in the recent SoCalGas ACAP" (TURN Opening Brief, p. 33). TURN goes on to state that it can see no reason for distinguishing between the two utilities on this policy question. The one caveat TURN makes is due to the AGD decision and argues for postponement of ratemaking treatment.

3. Discussion

We are somewhat dismayed that parties spent so much time rehashing their positions in the SoCal ACAP. Given the amount of space devoted to this issue in their briefs, it is sadly surprising that new arguments were not developed or old arguments improved. The only new twist is the AGD decision, which got a "do nothing" response from some parties.

The parties have not persuaded us that we should alter the careful and considered analysis and conclusion we reached on this issue in the SoCal ACAP. (D.90-01-015.)

DRA's equitable sharing mechanism will provide PG&E with a reasonable opportunity to recover take-or-pay costs while striking a fair balance in allocating risks and costs between PG&E's ratepayers and shareholders. As we observed in D.90-01-015:

> "SoCal may be entirely correct in claiming that the economic and market forces which gave rise to the problem were beyond the control of company management, but SoCal fails to recognize that these forces were to an even greater degree beyond the control of SoCal's ratepayers...
>
> "Under the circumstances, we conclude that it would be inequitable to allocate all of the risks of the events which gave rise to the take-or-pay problem and all of the costs incurred as a result of these events to ratepayers while allocating none to SoCal's shareholders." (D.90-01-015, pp. 52-53.)

We find our analysis of the take-or-pay issue to be equally applicable in this proceeding. For purposes of the rate tables attached to this decision, we have assumed PG&E has opted for the 100% recovery through a volumetric surcharge without balancing account protection. As we adopted for SoCal, a "one-way" balancing account for core allocated amounts will be imposed under the all volumetric recovery option. However, in light of the recent AGD decision we will make the amount of take-or-pay costs put into rates under DRA's proposed mechanism subject to refund. This will protect ratepayers from overpayment and avoid mounting interest obligations.

IV. Alternate Fuel Prices Forecast

The forecast of alternate fuel prices is a critical element in the ACAP. These prices constitute one of the fundamental inputs into the discount adjustment model (discussed later in this decision), which is used to forecast the amount of revenue PG&E can expect to collect from its noncore transportation customers given the alternative fuel prices available to those customers.

A. Crude Oil-Price Forecast

1. PG&E's Position

PG&E forecasts an average price of $17.78/Bbl for the RACC of imported crude oil for the ACAP forecast period. Broken down by quarters, these prices are $17.20, $17.65, $17.95, and $18.30, for the second, third, and fourth quarter of 1990 and the first quarter of 1991, respectively. PG&E produces its crude oil price forecast using DRI's world oil model. The model forecasts the RACC of imported crude oil, which represents the average cost to U.S. Refiner's of acquiring the various types and grade of crude oils used in the refining process. The U.S. Department of Energy (DOE) maintains the RACC data series. PG&E points out that the RACC price includes the cost of crude oils acquired through various transactions such as spot purchases, contract purchases, net back arrangements, and barter agreements.

PG&E maintains that since the RACC of imported crude oil is a composite of the many types of crude oils, it is a better indicator of the trend of average crude prices than any region specific crude oil price. PG&E believes that this enables the RACC to better capture the world oil market's general trend.

2. <u>DRA's Position</u>

DRA's recommendation is very close to that of PG&E's. DRA forecasts oil prices of $17.50/Bbl for the second, third, and fourth quarter of 1990. For the first quarter of 1991, DRA forecasts a price of $18.00/Bbl (DRA Exhibit 37). In deriving these numbers, DRA relied on the Energy Information Administration (EIA) for an oil price forecast. DRA points out that like the PG&E forecast, its forecast is based on the RACC. DRA notes there are some slight differences between the PG&E model and the EIA model relied on by DRA. DRA acknowledges, however, that the difference between DRA and PG&E forecast is so small as to be insignificant. The PG&E yearly average imported RACC of $17.78/Bbl compares to the DRA yearly average of $17.63/Bbl.

Despite this insignificant difference, DRA believes that its forecast should be adopted because it is based upon more appropriate methodology for the ACAP proceeding. DRA argues that its EIA forecast guarantees an unbiased result that is easily updated in future proceedings. By contrast, DRA asserts that the PG&E forecasting method relies upon the discretion of PG&E over the input assumptions, which has the potential of leading to a biased result. DRA asks that the Commission adopt DRA's oil price forecast in this ACAP and encourage all parties to rely on the EIA forecast in future ACAPs.

3. <u>Discussion</u>

We find very little to discuss when the crude oil forecast is so close between PG&E and DRA. Since PG&E went on to calculate its alternative fuel prices discussed in the next section, we will adopt its forecast of $17.78/Bbl for this ACAP period. We are not persuaded that the EIA forecast should be made mandatory in future ACAPs.

B. Alternative Fuel Prices Forecast

PG&E forecasts the wholesale and retail prices for No. 6 low sulfur fuel oil to be 23.3¢/th and 27.9¢/th, respectively. PG&E forecasts wholesale and retail prices for No. 2 distillate to be 37.6¢/th and 41.2¢/th, respectively, and finally forecasts wholesale and retail prices of propane to be 39.2¢/th and 51.7¢/th, respectively. We note that DRA states that it is in general agreement with this alternative fuel prices as calculated by PG&E. Since we have adopted PG&E's crude oil prices of $17.78/Bbl, we can also use these alternative fuel prices as calculated. These prices will best be adopted for purposes of the discount adjustment calculations. In addition, we adopt an alternate fuel price for refineries of 33.9¢/th for use in the discount adjustment calculation.

V. Gas Throughput Forecast

A. Overview

Gas throughput is a measure of the total demand for natural gas that can be supplied during the ACAP period. It reflects forecast gas demand, forecast gas supply, and any curtailments forecast during the ACAP period as a result of gas supply or system capacity constraints. Throughput estimates are a key factor used in allocating costs among the various classes of customers, thus having a direct effect on rates. Reasonably accurate throughput estimates are important in order to fairly allocate costs among customers, and to provide the utility with a fair opportunity to earn its authorized rate of return.

There are two components of the gas throughput forecast: the econometric forecast and the noneconometric or exogenous forecast.

The jointly prepared comparison exhibit (Exhibit 73) discusses some of the differences between the DRA and PG&E approach. Both DRA and PG&E developed econometric throughput forecast for the residential, commercial, industrial, steam heat, interdepartmental, and gas department use classes of service as well as for LUAF gas volumes. Referring to the comparison exhibit, for most classes of service the forecast between DRA and PG&E are relatively close. The largest difference occurs in the steam heat class of service where DRA's econometric forecast exceeds PG&E's by 7.4%. DRA and PG&E's total econometric throughput forecasts differ by less than 1%.

Even though the results of the DRA and PG&E econometric throughput estimates are close, DRA encourages us to adopt DRA's throughput estimate because it results from the DRA models containing the forecast assumptions developed by other DRA witnesses (DRA Exhibit 37). DRA argues that although the forecasts are close, each is based upon a different level of assumed discounting. DRA maintains that if the level of discounting would change, the results would begin to differ by large amounts. DRA notes that the discount levels affect the delivered gas prices used in the econometric model. Further discussion on some of the differences in the inputs to the econometric models will be addressed in sections below.

B. Residential and Commercial Throughput

PG&E forecasts a residential throughput of 2,129 MMth, and the commercial throughput of 867 MMth. DRA's forecasts are very close, being 2,159 MMth for the residential class and 843 MMth for commercial throughput.

PG&E concedes that the primary difference between PG&E's and DRA's residential and commercial throughput forecasts is that DRA assumes much lower average burner tip (commodity plus transportation) gas prices as inputs to the econometric models. PG&E claims that its burner tip gas price assumptions are superior since they are derived directly from PG&E's forecast of gas prices for the forecast period. However, we note that we have chosen not to adopt PG&E's gas price forecast for the test period. Therefore, we are persuaded that it would be more appropriate to adopt DRA's throughputs for both residential and commercial.

C. Industrial Throughput

1. PG&E's Position

PG&E has forecasted 1,512 MMth of industrial throughput. PG&E derives this number from the econometric model forecast of 1,743 MMth, from which two items are subtracted. First, 181 MMth are subtracted to capture the effect of the transfer of industrial load from the industrial throughput forecast to the cogeneration forecast. In PG&E's view, this deduction reflects the fact that part of the cogeneration load serves the industrial energy demand formerly provided through the industrial load.

Second, PG&E has subtracted 50 MMth to reflect the fact that the usage at Chevron's Richmond Refinery will be less than the historic use embedded in the industrial throughput data because of the recent fire at the refinery. (Exhibit 1, p. 4-5.)

PG&E describes the similarities between its and DRA's methodology to develop an industrial throughput forecast. Both forecast industrial throughput using an econometric method, and then subtract 30% of their respective rate schedule G-COG forecast of cogeneration throughput to reflect the transfer of industrial throughput to the cogeneration load. PG&E goes on to explain three reasons for the difference between PG&E's and DRA's industrial throughput forecast. PG&E points out that DRA chooses not to incorporate the 50 MMth adjustment to reflect the effect of the Chevron fire. PG&E asserts that a change in circumstance of such magnitude should be incorporated into a forecast. Econometric models assume that historic practices continue into the future, and unexpected shocks such as the Chevron fire, in PG&E's view, create a significant deviation from historic throughput practice which must be exogenously incorporated into the econometric forecast.

The second reason for the difference between PG&E and DRA's throughput estimates is, in PG&E's view, due to DRA's choice of economic indicator inputs to its industrial throughput forecast that have the effect of increasing its industrial forecast. PG&E points out that for both its residential and commercial throughput forecast, DRA used economic indicators consistent with UCLA's forecast of U.S. and California economic activity. PG&E further points out that for DRA's forecast of industrial throughput, DRA used an economic indicator which was derived from DRI's forecast of U.S. economic activity. PG&E asserts that the DRI and UCLA forecasts are inconsistent. PG&E maintains that the DRI forecast in particular assumes more robust growth for the California economy during the ACAP forecast. PG&E asserts that the consequence of DRA's inconsistent use of economic inputs for its throughput forecast is that its industrial forecast is higher than it would be if DRA had used the UCLA economic indicators as it did for purposes of its residential and commercial forecast. PG&E maintains that DRA's industrial throughput forecast would have been approximately 2.8% lower if it had made consistent use of the UCLA indicators.

The third criticism PG&E has of DRA's industrial throughput is the specification of the econometric model used to develop it. PG&E criticizes the model because it does not reflect any isolated dependence of throughput on the price of gas. PG&E claims that industrial econometric models typically incorporate the gas price in both the gas-own price and gas cross price variables. PG&E suggests that DRA's model does not incorporate the own price gas variable. PG&E maintains that the practical effect of this in DRA's model is that so long as the ratio of gas and oil price is expected to remain constant, DRA's model forecasts the exact same level of gas usage. According to PG&E, this would be so even if the price of gas doubled, tripled, or was cut in half. PG&E argues that such a model simply is not consistent with reality or economic intuition and that should be rejected.

PG&E also comments on the throughput forecast of TURN. PG&E asserts that the output of TURN's econometric model is unreasonably high. In addition, PG&E criticizes TURN's model for, in its view, incorrectly using a floor price for natural gas, when its model is specified to use average prices; making improper use of the gas and oil-minus-gas variables, varying one but keeping the other fixed; using nominal (not inflation adjusted) values in the oil-minus-gas variable; and finally incorporating an unnecessary trend variable in order to artificially lower throughput in a failed effort to make its forecast even remotely possible.

PG&E concludes that its own industrial throughput is the most appropriate in this record. PG&E's forecast use a consistent set of economic indicator variables whereas DRA uses an inconsistent set of inputs into its industrial throughput forecast. PG&E argues that since its industrial throughput model reflects the fact that gas consumption decreases when gas prices increase, provides a more realistic reflection of the relationship between gas prices and throughput levels.

2. DRA's Position

DRA's estimate for industrial throughput as set forth in the comparison exhibit is 1,582 MMth. DRA takes issue with PG&E's criticism of its forecast and the inputs used in its econometric model. DRA feels quite justified using the DRI forecast of U.S. industrial production for its input in the industrial throughput forecast. DRA argues that PG&E's criticism of its use of UCLA inputs and DRI inputs for different throughput estimates is meaningless. DRA points to PG&E's own workpaper that shows the difference between the DRI and UCLA variables is in fact very slight (Exhibit 66). DRA points out that the difference between the DRI and UCLA forecast for the real GNP in 1990 is only about 1%. In DRA's view, these slight differences do not support the criticism that PG&E has leveled at DRA's industrial throughput. DRA encourages the Commission to adopt its econometric industrial throughput estimates because it believes it is based on appropriate models and are consistent with forecast assumptions obtained from other DRA witnesses.

3. TURN's Position

As set forth in the comparison exhibit, TURN is recommending an industrial throughput of 1,638 MMth. TURN argues that PG&E criticizes its forecast because PG&E simply does not like the results. TURN points out that its basic industrial forecast is virtually equal to the recorded throughput to the year ended June 30, 1989 (Exhibit 52 and Exhibit 5). TURN asserts that while gas commodity prices are forecasted to rise somewhat, oil prices and industrial production have also increased, tending to offset the former change.

CIG/CLFP supports adoption of TURN's estimate of industrial throughput. CIG/CLFP believes TURN's approach is the most accurate of the three models presented. CIG/CLFP points out that TURN's model calculates unadjusted throughput using an assumed "floor" price based on PG&E's estimate of No. 6 fuel oil prices instead of the average "seed" price. CIG/CLFP believes this difference is what principally causes TURN's higher unadjusted throughput forecast.

4. Discussion

We are persuaded that PG&E's industrial throughput forecast is the most reasonable. We note that the results of DRA and PG&E's models are quite close. One difference is PG&E's subtraction of 50 MMth to account for the Chevron refinery fire. We agree with PG&E that it is appropriate to subtract from the total throughput an amount to allow for the circumstances of the Chevron fire. Our overall goal is to have all of our forecast come as close to reality as possible. To ignore a known reality of the magnitude of the Chevron fire and the consequences for PG&E sales would be inappropriate.

While not necessarily agreeing with all of PG&E's criticisms of TURN's econometric model, we are persuaded that PG&E's approach is a better one. Therefore, we will adopt the figure of 1,512 MMth for the industrial throughput forecast.

D. Interdepartmental, Gas Department Use, LUAF, and Steam Department Throughput

PG&E and DRA are the only parties to develop forecasts for these categories. PG&E's and DRA's interdepartmental, gas department use, and LUAF throughput forecast are identical. They are as follows: interdepartmental use is 3 MMth, gas department use is 60 MMth, and LUAF is 169 MMth. As to the steam heat throughput, DRA estimates 11 MMth while PG&E estimates 10 MMth.

Since they are a function of the overall throughput (except for steam) and of small magnitude we shall adopt these as a percentage of the annual throughput.

E. Cogeneration, EOR, and Wholesale Throughput

These throughput forecasts were also undisputed between DRA and PG&E. Both parties forecast 602 MMth of cogeneration throughput (Rate Schedule G-COG) and 358 MMth of EOR throughput. Likewise, PG&E and DRA also agree on a wholesale throughput forecast of 112 MMth. There being no dispute regarding these numbers, we will adopt them as the throughput forecast for these categories.

F. GC-2 Contracts Throughput

Since both DRA and PG&E agree that there will be 231 MMth of industrial GC-2 throughput, we will adopt that figure. Likewise, the parties agree to 119 MMth of cogeneration GC-2 throughput during the ACAP forecast period. We believe it is reasonable to adopt these agreed upon numbers.

G. PG&E Utility Electric Generation Throughput

As DRA notes in its opening brief, PG&E's electric department is the largest single user of natural gas in PG&E's service territory. PG&E and DRA have reached agreement on a forecast on 1,309 MMth (Comparison Exhibit 73, p. 11). In addition, PG&E and DRA agree on a forecast of start up fuel of 13 MMth during the test period. Once again, we find no reason to do anything but adopt these stipulated numbers.

H. SCE Cool Water Utility Electric Generation Throughput

1. PG&E's Position

PG&E serves SCE's Cool Water plant located near Barstow, California. PG&E has forecasted that the baseload of the Cool Water plant will be 38 MMth for the ACAP test period. This is the same level adopted in PG&E's last ACAP. PG&E is troubled by DRA's recommendation that a figure of 120 MMth be used as a throughput forecast. PG&E points out that DRA has derived this number as a result of a stipulation in A.89-05-064, an SCE Energy Cost Adjustment Clause (ECAC) proceeding. PG&E asserts that it was not a party to this stipulation and had no part in the formation or review of this forecast. PG&E points out that as a stipulation, the Cool Water forecast adopted in the SCE ECAC proceeding is a compromise rather than a fully litigated result. PG&E objects that DRA presented no evidence as to the appropriateness of this stipulated throughput in this ACAP proceeding. PG&E argues that the DRA witness sponsoring this forecast seemed to know very little about the basis for the stipulated load in the ECAC proceeding.

PG&E is particularly concerned with DRA's treatment of this 120 MMth Cool Water load forecast in its discount adjustment calculation. PG&E claims it cannot be determined from DRA's workpapers whether or not this Cool Water load was included in its discount adjustment calculation in a manner which reflects the required substantial discount PG&E must make to SCE.

2. DRA's Position

DRA based its forecast upon the results of the ELFIN production cost model, and incorporates the generation resource mix assumptions that parties have settled on in the latest SCE ECAC proceeding (A.89-05-064). DRA asserts that the ELFIN forecast in the SCE ECAC provides monthly gas demand data for the plants for April through December 1990 of the ACAP period. DRA then projects SCE gas demand for January through March 1991 based on expected demand in the corresponding months of 1990. The DRA forecast for SCE demand is 120 MMth (Comparison Exhibit 73, p. 11).

DRA notes that PG&E does not rely upon an updated forecast of SCE's Cool Water demand. Instead, DRA criticizes PG&E for simply carrying over the level adopted in PG&E's last ACAP. DRA disputes PG&E's rationale offered for the use of the old forecast, being that there is uncertainty about SCE's electric dispatch decisions, and in turn, about the amount of generation expected from SCE's Cool Water generating plant. DRA argues for adoption of its forecast because it believes it is based upon the current circumstances, and is the most current forecast available. DRA also argues that there is a benefit to maintaining consistency with the SCE ECAC decision. DRA points out that PG&E has essentially declined to do a forecast because of the uncertainties of forecasting. DRA believes this proceeding will be better served by adoption of the DRA forecast.

3. Discussion

Here we are faced with a situation where DRA and PG&E have seemingly changed hats on their views on the merits of forecasting in the world of uncertainty. It was that concern over uncertainty and forecasting and the accompanying signal to the marketplace that led us to take a conservative approach in our gas price forecasts in this decision. Likewise, we are troubled by

DRA's position that because a stipulation was reached in another proceeding, PG&E, who was not a party in that proceeding, should be bound by the result here. Further, DRA's witness on this subject did not seem to understand a great deal about the background for that stipulated number in the SCE ECAC. For these reasons, we will adopt PG&E's forecast of 38 MMth of throughput for the SCE Cool Water plant.

I. Interutility Throughput

1. PG&E's Position

The interutility throughput forecast is clearly the most controversial throughput forecast in this ACAP proceeding. PG&E recommends that an interutility throughput of 90 MMcf/day or 345.79 MMth be adopted for the test period based on historical interutility throughput level. In support of its reliance on historical interutility throughput levels, PG&E points out that during the first 12 months of the new industry structure, May 1988 through April 1989, interutility throughput averaged about 110 MMcf/day. PG&E argues that about 20 MMcf/day of this volume can be attributed to targeted gas sales. PG&E points out that these sales were priced at a level which was competitive with other supplies available to interutility customers. PG&E notes that it no longer makes such targeted sales as directed by the Commission. Without this ability to target gas supplies outside of PG&E's portfolios, PG&E believes that an interutility throughput estimate of 90 MMcf/day is justified. PG&E lists several factors that should govern any attempt to forecast interutility volumes: (1) since interutility transportation service has the lowest priority on the PG&E system, it can occur only to the extent pipeline capacity is available; (2) an interutility customer must desire transportation coincident with capacity being available; (3) SoCal must have capacity available at the desired point of delivery into its system; (4) for sales related interutility transport to occur, PG&E must have supplies available in excess of

PG&E's system demands at a competitive price; (5) for interutility transport to occur for customers other than SoCal, the cost for gas supplies available through PG&E's system must be below the cost for gas supplies available through SoCal's system by at least the amount of the interutility rate, plus a large enough margin to make the gas attractive (Exhibit 1, pp. 5-17 and 5-18).

PG&E argues that neither DRA nor TURN took these factors into account in developing their respective interutility forecasts.

PG&E argues that DRA's interutility forecast workpapers provide little insight into the factual basis for DRA's position. PG&E argues that DRA has not done any quantitative analysis for its forecast proposal. Instead, PG&E claims that DRA's forecast appears to be based on a series of general assumptions which are factually incorrect. To support its claim, PG&E points out DRA's conclusion that interutility throughput will increase as the result of a return to normal hydro conditions and additional output from the Diablo Canyon plants. PG&E maintains that the review of historical data on levels of interutility throughput do not indicate any such correlation. Generally, PG&E criticizes both DRA and TURN's interutility forecasts for failing to take into consideration the several interrelated factors that determine the level of interutility load.

2. <u>DRA's Position</u>

DRA's forecast for interutility throughput is substantially higher than PG&E's. DRA projects test period throughput for interutility transport to be 638.750 MMth for an average of 168 MMcf/day. DRA takes issue with PG&E's characterization of its interutility throughput forecast, DRA believes its own to be quite a conservative forecast.

DRA's forecasting methodology was to determine the amount of interstate capacity that would be available given DRA's forecast of on-system customer demand. DRA acknowledges that it accepted

PG&E's assertion that there would be little or no interutility service during the winter heating season. DRA notes that it also accepted SoCal's assertion that it could take a maximum of 300 MMcf/day of interutility deliveries during the summer months, because of constraints on injecting gas into storage.

DRA claims to verify the feasibility of meeting its interutility forecast by assuming that the PGT system would deliver at 95% capacity, that PG&E's southern system minimums would be met, and El Paso deliveries would never exceed 95% of capacity in any month. DRA believes that these factors support its contention that its forecast is actually very conservative.

DRA is critical of PG&E's use of interutility historical data to develop its forecast. DRA objects to what it views as PG&E's unwillingness to make a forecast of interutility throughput despite the fact that this is supposed to be a forecasting proceeding.

Finally, DRA suggests that the conclusion the Commission reached in its recent decision in the SoCal ACAP supports its position also. In that decision, the Commission adopted an interutility forecast of 165 MMcf/day (D.90-01-015, p. 20). DRA notes that this is almost identical to the DRA interutility forecast of 168 MMcf/day in this proceeding. DRA urges adoption of its forecast in this proceeding, not only because it is consistent with the SoCal ACAP decision, but because it is supported by ample evidence in the record.

3. <u>TURN's Position</u>

TURN forecasts interutility throughput to be 1,038.75 MMth or an average of about 275 MMcf/day. This throughput is higher than either DRA's or PG&E's. TURN provides the following rationale for its throughput forecast. TURN argues that it must be recognized that there is very significant demand for pipeline capacity in Southern California due to current and forecasted capacity curtailments on the SoCal system. TURN believes that either SoCal itself or its UEG customers who bear the brunt of curtailment will be eager to take advantage of available excess PG&E capacity under most circumstances. Further, TURN argues that PG&E has ample unused capacity over its Line 300 to accommodate the entire DRA forecast, still leaving an average of 100 MMcf/day idle and unused. TURN concludes that the utilities will never cooperate to the extent necessary to maximize interutility transportation unless and until this Commission puts them at financial risk for their failure to do so. TURN urges that the time to begin is now, by adopting TURN's forecast of interutility volumes. Finally, TURN notes that it proposed essentially the same figure in its comments on the proposed decision in the SoCal ACAP.

4. SoCal's Position

SoCal supports PG&E's estimate of 90 MMcf/day in this ACAP period. SoCal supports adoption of this throughput forecast because it is based upon actual historical data. SoCal believes that the interrelated workings of all of the factors which PG&E listed in its testimony as impacting interutility throughput reflect the actual workings of the market-oriented gas pipeline systems of PG&E and SoCal and therefore should be given great weight in the adoption of an interutility throughput forecast. SoCal believes it is unrealistic to assume 100% of theoretically available gas transportation capacity can be utilized due to these operating factors and constraints. SoCal quotes Finding of Fact 29 from its SoCal ACAP decision, D.90-01-015:

> "SoCal will not be able to take advantage of the full theoretically available excess transportation capacity from PG&E because SoCal and PG&E can sometimes be expected to have high system demand during the same periods of time."

In conclusion, SoCal argues that DRA's analysis is extremely limited in its analytical nature and makes no attempt to appreciate or understand the dynamics of interutility transportation.

5. <u>Discussion</u>

The forecast for interutility throughput was the most contested of all the gas throughput issues in this proceeding. We believe it appropriate to quote a section from the recently issued SoCal ACAP decision:

> "This is a very complex issue argued largely on the basis of qualitative evidence, but requiring a quantitative resolution. Interutility transportation throughput from PG&E to SoCal is the lowest priority of service for PG&E, and can be provided only to the extent that PG&E's system capacity and gas supply exceed PG&E's own higher priority demands. Unfortunately no analysis of PG&E's system capacity, supply, or demand was developed in this proceeding, nor was any rigorous analysis of the assumption underlying our decision in PG&E's most recent ACAP offered. As a result, no quantitative determination of interutility transportation capacity or throughput from PG&E to SoCal can be made. Interutility throughput can only be forecast on the basis of qualitative factors, informed judgment, and recent experience." (D.90-01-015, p. 16.)

DRA points to the fact that the number finally selected in the SoCal ACAP is very close to its number recommended here. We point out, however, that the number selected in the SoCal ACAP was a number that had not been recommended by any one party. The lesson we conclude from our SoCal ACAP decision is that it is appropriate to pick a number somewhere in between those recommended by the parties when it is such a qualitative judgment call. Further, we are unconvinced that DRA truly took into account all of the factors which PG&E says are necessary to weigh in attempting to forecast interutility throughput. We note that SoCal in its brief filed in this proceeding supports PG&E's position.

We think TURN's recommendation is simply too high and somewhat punitive in nature. Frankly, none of the throughput forecasts proposed by the parties are particularly persuasive. We believe some increase over the last ACAP forecast amount is appropriate, therefore we will not adopt PG&E's recommendation of 90 MMcf/day. However, we did not believe the evidence supports either DRA or TURN's recommendations. PG&E successfully attacked both of those positions. Given the conflicting evidence on this issue, we will adopt an interutility throughput forecast of 120 MMcf/day or 460 million therms.

J. <u>Discount Adjustment</u>

1. <u>Overview</u>

The Commission has authorized gas utilities to discount rates in order to increase the sales volume over which the utilities' fixed costs are spread. This discount adjustment is a mechanism used to adjust the noncore revenue estimate to reflect the amount of incremental, or additional, revenue a utility can earn from noncore industrial sales through discounting. The discount adjustment allows PG&E an opportunity to recover its authorized revenue requirement by reallocating the incremental revenue difference to other customers.

This reallocation is necessary because cost allocation for the gas industry is done on the basis of throughput. When customers received discounts below fully embedded costs, thereby increasing throughput, an adjustment must be made to allocation. Throughputs for various rate classes are used as determinants in allocating costs. Therefore, this adjustment to the allocation is effected through a reduction in allocation determinants for rate classes receiving the discount and a proportionate increase in the determinants for other rate classes. This adjustment to allocation does not imply an expected reduction in actual throughput. It is merely the translation of a revenue adjustment into a volume adjustment that is used for cost allocation and rate design purposes only. If this adjustment were not done, it would result in more costs being allocated to alternate fuel capable customers than could be recovered in rates.

The purpose of discounting rates is to retain customers who are unwilling to pay tariff rates, but who are willing to pay rates that are high enough to make a contribution to fixed costs. This retention of customers through discounting benefits customers on the default rates because it spreads the fixed costs over a larger amount of throughput. The result is that default rates are lower when discount customers are retained than if those customers left the system.

How to arrive at an appropriate discount adjustment was the subject of much controversy in PG&E's last ACAP proceeding. (D.89-05-073.) The discount adjustment calculation adopted in the last ACAP had been proposed by TURN. In this proceeding, both PG&E and DRA essentially used the same discount adjustment model that was adopted in the last ACAP decision, with some important differences which will be discussed below. However, TURN has modified its original proposal and in this proceeding is now recommending an all econometric model, termed the Miller Approach after the SoCal witness who sponsored such an approach in the SoCal ACAP. It should be noted from the outset that the TURN and DRA methods produced fairly similar recommendations of the percentage of discount required, despite differences in methods.

2. <u>PG&E's Position</u>

While PG&E is essentially using the same discount adjustment model as was adopted in its last ACAP, PG&E proposes several modifications to the structure and to the inputs of the discount adjustment model which impact the end result. PG&E proposed to modify the model by: (a) establishing a customer group for refineries; (b) reducing the $0.02 gas premium to zero for refineries; and (c) excluding the D1 demand charge from the exit cost calculation.

In light of these modifications, PG&E comes up with a level of discounting of approximately 30% for its new proposed G-NCT Schedule (the combination of the current G-IND and G-P2B

Schedules it is suggesting as a rate design modification) and 11% for the G-COG Schedule. PG&E argues that since its proposal is consistent with that adopted in its last ACAP it should be used in this proceeding also.

PG&E spends most of its time in both its opening and reply briefs attacking the methodology presented by TURN in this proceeding. We note that it would have been more helpful if PG&E devoted more time to justifying its own position. We will summarize briefly PG&E's criticism of TURN's econometric methodology.

PG&E asserts that the TURN discount adjustment calculation overforecasts throughput and revenues and underforecasts the discount adjustment factor. Because PG&E believes that TURN's industrial econometric model of unadjusted throughput is too high, its discount adjustment calculation is also flawed. PG&E points out that TURN's methodology projects that PG&E will be able to recover $279 million in revenue from the noncore customers for transportation services during the forecast period. PG&E compares this with an amount of $265 million adopted in last year's ACAP. PG&E points to the undercollection in the negotiated revenue stability account (NRSA) which indicates in its view that last year's adopted figure was substantially too high.

Likewise PG&E argues that TURN's discount adjustment calculation forecast an unreasonably low discount percentage of approximately 8%.

Another criticism PG&E levels at TURN's methodology is that in order to determine discount percentages, the cost allocation and discount adjustment steps of the ACAP process must be iterated until they converge. PG&E argues that because of this one cannot tell what the actual discount adjustment factor obtained from TURN's approach would be. PG&E criticizes this failure to carry out the necessary iterations, arguing that there is no way for the Commission or any party to know what the "real" results will be from TURN's recommended approach.

PG&E finds flaws in TURN's use of its econometric model for its discount adjustment calculation. PG&E claims that TURN ignores the fact that the econometric model assumes the gas price variable represents an average price of gas. PG&E criticizes TURN for not using the real prices of oil and gas in its oil minus gas variable, consistent with its use of the real price of gas in its gas-owned price variable. PG&E accuses TURN of incorporating a trend variable into its econometric model for the express purpose of lowering its forecast. PG&E claims that the reason TURN's forecast is too high is because TURN plugs in too low a gas price. In sum, PG&E believes that TURN's econometric model is fatally flawed and should not be adopted in this proceeding.

3. DRA's Position

DRA likewise bases its discount adjustment calculation on the methodology approved in last year's ACAP. Since supposedly PG&E did the same, DRA attempts to explain why the results between the DRA and PG&E positions are significant. DRA lays the blame on the modification PG&E made to the discount adjustment model. DRA's objections to these modifications are threefold: (a) PG&E's estimate of the exit cost is erroneous; (b) PG&E understates the premium; and (c) the adopted discount adjustment should be no more than the level of discounting PG&E must make to retain load.

DRA proposes to include one-half of the D1 demand charge in the exit cost portion of the discount adjustment. DRA's final recommendations of the discount adjustment factors are as follows: a 13% discount factor for the G-IND class, a 2.1% discount factor for the G-P2B class, and a 4.3% discount factor for the G-COG class. These percentage discount factors have changed slightly based on the cost of gas numbers put forth in Exhibit 38.[1]

DRA believes that these proposed modifications to the discount adjustment methodology which PG&E makes would severely overestimate the amount of discounting that is required. Another fact is that more costs (from the discounted adjusted throughput) would be shifted to core customers from the noncore. As a consequence, PG&E faces less risk in recovering its revenue requirement because more costs have been reallocated to core customers.

DRA asserts the primary reason for the differences in PG&E's level of discounting in this year's ACAP from last year's ACAP is the way which PG&E has estimated the exit cost. In PG&E's last ACAP, the Commission adopted an exit cost level of one-half of the D1 demand charge. DRA disagrees with PG&E's reasoning for the omission of D1 demand charge. PG&E leaves it out because it believes that the D1 charge that a customer pays during months of alternative fuel use would be recouped in future months by reductions in D1 demand charges when the customer returns to PG&E's system. DRA argues that the evidence presented at hearing is quite different from this assertion. DRA points out that PG&E has not presented any testimony from any of its customers that supports PG&E's analysis that its customers ignore demand charges when performing a fuel switching analysis. PG&E's exclusion of the D1 demand charges in its exit cost calculation is premised on the belief that the customer will in fact come back to the PG&E's system. DRA points out that there is no ramping-up in that the customers know the D1 demand charge will start at the current

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1 We note that we have not relied on the cost of gas numbers in Exhibit 38 in our prior discussion in adoption of cost of gas figures.

month's volume divided by one and then build up until there is a 12-month history. Also, if the customer has a volumetric rate or leaves the PG&E's system entirely, there would not be any ramping up effect.

DRA points to another problem with PG&E's exclusion of the D1 demand charge from its exit cost calculation in that it fails to consider the time value of money, and what type of rate structure there will be in the future. If the so-called ramp-up benefits do not occur until the future, those future benefits would have to be discounted to present value so that the future benefits can be easily compared to the near-term ramp-down costs. Also, if for example, the rate structure changes to an all-volumetric structure in the future, there will be no recapture of the ramping up of the D1 charge. DRA notes that the exit costs it is recommending for use in the discount adjustment calculation are lower than those adopted in last year's ACAP. In last year's ACAP the Commission adopted a weighted average exit cost number of 4.4¢/th to be used in the discount adjustment calculation. In this proceeding, DRA recommends exit costs of 2.224¢/th for G-IND and 2.859¢/th for G-P2B and G-COG customers.

The other major area of difference between DRA and PG&E's discount adjustment calculation relates to the premium for gas used in the discount adjustment model. A two-cent premium for gas was adopted by the Commission in its implementation decision, D.87-12-039 and in PG&E's last ACAP. PG&E has abandoned this two-cent premium in its discount adjustment calculation for the refinery category. DRA disputes this. DRA argues that the premium was used as an overall average for all customers in the discount adjustment. DRA notes that if the premium were to change to zero for refineries, as PG&E has proposed, then one should see a correspondingly higher average for other customers. DRA argues that its 2¢ premium should be used for all categories in its discount adjustment model.

Finally DRA briefly comments on TURN's proposed econometric discount adjustment methodology. While DRA states it is receptive to the use of TURN's econometric discount adjustment, it sees a problem with TURN's method in that it is difficult to implement with the lag dependent variable structure. DRA notes that both the DRA's and PG&E's forecasting equations have a lag dependent variable structure. For this reason, DRA recommends that its discount adjustment methodology should be adopted for purposes of this ACAP proceeding rather than TURN's econometric model.

4. <u>TURN's Position</u>

TURN is affronted by PG&E's characterization of its econometric discount adjustment methodology in PG&E's opening brief. TURN believes PG&E has seriously mischaracterized its methodology. TURN states that its methodology was based on the approach employed by DRA and SoCal in the latter's recent ACAP proceeding. TURN acknowledges that its prior methodology was adopted in PG&E's last ACAP. However, TURN quotes the Commission decision:

> "While we endorse TURN's model in this proceeding, we recognized that refinements or changes to it may be appropriate as PG&E and intervenors gain experience with ACAP forecasting in the marketplace. Accordingly we invite PG&E and other interested parties to propose changes in future ACAPs." (D.89-05-073, p. 21.)

TURN has essentially adopted the more refined discount adjustment methodology which SoCal proposed in its first ACAP. According to TURN, that proposal, sponsored by witness Miller, eliminated the two-step process of first forecasting "unadjusted" industrial throughput via an econometric model and then developing the discount adjustment factor using an entirely different approach. Instead, SoCal proposed using the basic econometric model to generate a consolidated and consistent throughput forecast and discount adjustment. TURN points out that this is accomplished by reiterating the econometric model with a series of progressively lower gas prices and the fuel switching variable, to simulate the effects of utility discounting to compete with alternative fuels. In essence, TURN argues that a single model is employed to estimate the demand curve for gas transportation. TURN maintains that the result is a forecast not only of total industrial throughput, but also of the revenues that can reasonably be recovered from transporting those volumes at a combination of default and discounted rates.

TURN argues that one of the major flaws of the separate discount adjustment model employed by PG&E is that it treats all customers with a given alternative fuel as if they behaved identically when it comes to fuel switching decisions. The result is an assumed demand curve that is discontinuous at the point where all customers with a given alternative fuel would purportedly either switch or demand the discount. TURN's method, on the other hand, assumes a normal smooth demand curve consistent with the linear structure of the econometric model and common sense observation of customer behavior. In TURN's view, another benefit is that it is not necessary to deal with the assumptions about premiums and exit costs. Thus two of the most controversial elements of this separate discount adjustment calculation are eliminated entirely under the unified econometric approach. TURN points out that the basic principles of this methodology were not challenged by any party in the SoCal ACAP proceeding.

TURN argues that PG&E's opposition seems to be based on two factors. First, PG&E does not like TURN's results. TURN asserts that this objection is obviously self-serving and should be given little weight. The second basis for PG&E's opposition seems to be that it believes that TURN has made improper use of the gas price term in its equation. TURN claims that PG&E's second objection is fundamentally the result of misunderstanding on PG&E's part as to what TURN's econometric witness, Mr. Marcus, actually did. TURN argues that the range of assumed rates that TURN used in the econometric model is fully consistent with the historical rate data upon which the econometric model is based. TURN asserts that PG&E is the party that has failed to improve its forecasting tools to reflect the much greater negotiating flexibility that the company has now as compared to the situation under the old industry structure. TURN argues that the use of a single average gas price for forecasting purposes simply does not provide an accurate estimate of the company's ability to maximize volumes and revenues in today's environment.

TURN asserts that it used conservative assumptions as inputs to its econometric model. For example, TURN valued the revenues associated with the removal of the Chevron fire-related volumes at full default rates. Further, TURN applied its calculated discount adjustment factor to all cogeneration (as well as industrial) volumes, even though most cogen load is forecasted exogenously from the econometric model.

TURN objects to PG&E's characterization that it set out to calculate the highest noncore revenue target that it could possibly justify for the PG&E's system. On the contrary, TURN's witness undertook to develop an estimate that was reasonable and achievable under the assumed conditions. TURN states that once the Commission has decided upon the various contested input assumptions issued in the case, such as oil and gas prices, the econometric discount adjustment methodology will have to be reiterated to achieve final convergence between the assumed "seed rates" and actual adopted default rates. TURN points out that it generally does not matter whose econometric model is used in this reiteration process.

Finally, TURN emphasizes that it is proposing the method already adopted for SoCal. TURN argues there is no operational or other practical or theoretical reason why the same discount adjustment methodology should not be applied to both utilities.

5. <u>CIG/CLFP's Position</u>

While CIG/CLFP did not present a discount adjustment calculation or methodology in this proceeding, in its brief it supports TURN's position. CIG/CLFP notes that while the discount adjustment concept is rather straightforward, in practice it has been extremely difficult to implement. In fact, CIG/CLFP declares the only consistent thing about the discount adjustment calculation is that it seems to change each time it is employed in a gas utility proceeding. CIG/CLFP argues that TURN's econometric model should be used for both the unadjusted and adjusted throughput forecasts for the industrial class. CIG/CLFP also alleges that TURN's methodology has fundamentally been approved in SoCal's ACAP, thus offering the prospect of consistent regulatory treatment of the two primary California gas utilities.

6. <u>Discussion</u>

Once again the parties have expended a great deal of energy (and pages of briefs) debating the relative merits or lack thereof of different ways to account for discounting to the industrial class. As we can glean from the record, both PG&E and DRA use a discount adjustment method that is based on an estimation of the maximum rate a customer would be willing to pay. This rate, which is equal to the sum of gas cost, gas premium, and exit cost, is calculated for three customer groups using three types of alternate fuel. The amount of discounting is assumed to be the percent difference between the maximum rate a customer group would be willing to pay and the default rate. As we see it, the reason PG&E and DRA reached different results is because PG&E does not include demand charges in its exit cost. We agree with DRA's criticism of PG&E's methodology on this point except as to refinery customers which will be discussed below. PG&E's discount adjustment factor of 30% is clearly out of line with historical trends. A discount factor of that level would take away too much risk and grant too great a likelihood of reward under the new regulatory structure. Our goal is for the discount adjustment factor to be as close to reality as possible.

In their comments on the ALJ proposed decision, PG&E and Chevron both disagree with the inclusion of exit costs and a 2¢ gas premium for refinery loads. We are persuaded by the arguments made in these comments that it is inappropriate to apply either exit costs or a 2¢ gas premium to refinery loads. As PG&E points out, approximately 95% of the refinery load is transported pursuant to contracts under with refineries have no obligation to pay termination charges, hence no exit costs. Therefore, the discount adjustment calculation reflected in the attached tables will reflect these changes.

In PG&E's next ACAP filing, we instruct PG&E to collect and present information regarding exit costs and gas premiums that exist in the real world for both default and nondefault customers. We expect this data to include refineries but not be limited to that group.

As we see it, the main philosophical difference between the methods used by PG&E and DRA and the TURN econometric method is that the former assumes that the customer's decision to use gas as a fuel is mainly dependent on the price of alternate fuel. The econometric method proposed by TURN assumes that the use of gas as a fuel is a function of the gas rate and a customer's demand elasticity. TURN suggested either model should produce similar results. Indeed TURN and DRA's discount adjustment factors are quite close in range. Once again we find the reason that PG&E's recommendation is out of line is because of its incorrect exclusion of demand charges in its exit cost calculations.

We are comforted by the fact that while approaching things differently, TURN and DRA's methodologies resulted in similar discount factors. Based on the gas cost and throughput numbers adopted in this decision, CACD will have to produce new tables for our decision. We have instructed CACD to input the adopted numbers in this decision and calculate the DRA discount adjustment calculation using DRA's approach. The resulting discount factors are somewhat higher than those reached by DRA and

TURN in their prepared testimony due to our changes regarding refinery load. The discount factors are 24.0% for G-IND class, 7.5% for G-P2B class, and 5.2% for G-COG class. For ease of implementation we will follow DRA's basic approach toward discount adjustment but have CACD run the calculation again based on our adopted inputs.

However, we find merit in the econometric proposal set forth by TURN and wish work in this area to continue, hopefully in time for the ACAPs to be filed in this calendar year. Frankly, we would prefer that a consistent methodology be employed for all three utilities. While TURN argues that its proposal in fact does this, we are concerned with the implementation of its proposal. Therefore we direct CACD to chair workshops on the discount adjustment methodology, particularly on TURN's approach. We encourage parties to attempt to reach consensus, but will authorize CACD to select the method which will be included in each utility's ACAP filing for this year. Our intention is to develop something similar to the base case runs that the utilities must make in their ECAC filings. Of course, we will allow a utility or any other interested party to propose an alternative methodology. Our goal however is to streamline and make uniform the discount adjustment in these proceedings in the hope of making them less controversial and time-consuming in the future.

We therefore order utilities and any other interested parties who wish (and we encourage TURN to do so) to submit proposals to CACD within 30 days detailing their discount adjustment methodologies. CACD shall then schedule workshops and give notice seven days in advance to all ACAP utilities and to all parties to this proceeding. CACD will then make a compliance filing setting forth the base case discount adjustment calculation that all parties are expected to use in the next round of ACAP filings. If the timing of this requires that SoCal and SDG&E amend their ACAP applications, they are ordered to do so. One of our goals of this approach is to enable our own CACD to be able to implement a consistent methodology and uniform ACAP logic for the utilities.

VI. Cost Allocation

A. Overview

Cost allocation is the heart of the acronym ACAP. Cost allocation involves the assignment of the authorized costs associated with the operation of the utility's system to the various customer classes for recovery through rates. These allocation rules were established by the Commission in D.86-12-009, and have been modified only slightly since then. The costs to be allocated generally fall into two categories: variable costs and fixed costs.

The principal variable cost, and the subject of much debate in the ACAP, is the cost of gas purchased by the utility. It is a variable cost because the total expense to the utility varies with the price of gas and the amount of gas sold. The allocation of the commodity cost of gas is straightforward. Customers are charged for the gas that they use on a cents per therm basis. Since the utility is required to sell the gas it purchases at cost, the core and noncore WACOGs adopted in the ACAP are based exclusively on the estimate of what gas will cost the utility during the forecast period. Any over and undercollections of core gas costs are captured in a balancing account and amortized in the next forecast period. The gas purchases going into the noncore portfolio are not protected by a balancing account. However, since the utility is free to change the price it charges twice monthly based on actual costs, the utility should be able to closely match revenues and expenses.

Fixed costs are relatively stable. They tend to be independent of the amount of gas flowing through the utility's system. The largest fixed cost which must be allocated is the revenue requirement adopted in the utility's most recent general rate case. Other examples of fixed costs include the pipeline demand charges incurred by the utility in shipping gas over the interstate pipeline system, the annual attrition adjustment, and the dollars accruing in various balancing accounts which are in need of amortization.

The total revenue requirement is first broken up into functional components which correspond to different aspects of the utility's operations. The five functional categories are production, transmission, storage, distribution, and general accounts. For example, all of the fixed costs associated with PG&E's gas storage system will be assigned to the storage category. Similarly, all of the fixed costs associated with the transmission system, which connects the distribution network to interstate sources of supply, will be assigned to the transmission function. In this manner, all of the fixed costs of the system will ultimately be assigned to one of the five functional categories. (Exhibit 1, pp. 6-3 to 6-5.)

However, before the costs can be allocated to the different customer classes, there is another step that must be performed. The costs within each functional category must first be "classified". That is, all of the costs within each functional category are classified as either being commodity related, demand related, or customer related. For example, those storage costs associated with fuel-related accounts are classified as commodity costs. The remaining storage costs, both expense and rate base, are classified as demand related since the underlying purpose of the storage system is to serve peak system demand.

Once the costs are functionalized and classified, they are allocated to the different customer classes using the allocation factors adopted by the Commission. All customer-related costs are allocated on the basis of weighted number of customers. Demand and commodity-related costs are allocated on the basis of throughput, usually either average year throughput or cold year throughput.

After the costs have been functionalized, classified, and allocated, rates are set to recover them. Costs are recovered in rates through either customer charges, demand charges, or volumetric charges. As a general rule, costs that were classified as customer related are recovered through the customer charge. For noncore customers, costs that were classified as demand related are recovered through demand charges while commodity-related costs are recovered in the volumetric charge.

Adjusting the allocation to account for reasonable utility discounting is where the discount adjustment calculation discussed in the previous section fits into the ACAP picture.

As evidenced by Part 2 of the Joint Comparison Exhibit (Exhibit 74), DRA and PG&E agree as to most of the allocating factors which should be used. Therefore, there is no need to discuss them here.

CACD has created its own cost allocation model which will be used to calculate the attached tables to this decision. CACD has done this in a continuing effort to work bugs out of cost allocation models and allow the Commission greater independence from the parties in the preparation of its attachments to its decisions.

However, there are a few areas of disagreement on cost allocation issues which must be resolved and will be discussed in the sections below.

B. Allocation of State and Federal Income Taxes

PG&E proposes that state and federal income taxes be allocated according to customer class. More particularly, PG&E proposes the results of the tax calculations be such that taxes are allocated to each of the various categories of customers in proportion to the responsibility of that class for the incurrence of the tax. PG&E notes that its allocation of taxes is consistent with treatment which has been used since the industry restructuring.

In its cost allocation model, DRA uses the functional components of the base revenue requirement as computed by PG&E's model. DRA uses PG&E's methodology for the computation of state and federal income taxes because DRA claims PG&E's tax calculation is at a level of detail that DRA cannot reproduce.

However, for rate design, DRA does something different than PG&E. In DRA's rate design, the DRA allocates total income taxes to functional groups based on the proportion of total rate base in each functional group. According to DRA, the differences between the DRA's and PG&E's method for rate design purposes result in differences in the assignment of costs within each noncore customer class from the demand and customer rate components to the volumetric rate component with no change in the class total. (Comparison Exhibit 73, pp. 26-27.)

DRA acknowledges that PG&E's proposal to compute state and federal taxes and return on a customer class basis is in conformance with the Commission's gas implementation decision, D.87-12-039, and Public Utilities (PU) Code § 739.6 (which mandates that the current cost allocation policy be retained by the Commission until December 31, 1990). However, DRA argues that DRA's method should be used for rate design purposes instead of PG&E's. DRA argues its method is "sufficiently accurate" for rate design purposes. (DRA Opening Brief, p. 44.) DRA alleges its method does not change the revenue allocated, and probably only has a small effect on the amount assigned to the volumetric rate component for G-P2B and G-IND customers. Finally, DRA argues that since San Diego Gas & Electric Company (SDG&E) and SoCal use something similar, conformity among ACAPs argues in favor of DRA's method.

We find using the same method for both cost allocation and rate design to be superior to DRA's proposal and therefore will adopt PG&E's position on this issue. We agree with PG&E that its method is fairer to the customer classes than DRA's "rate base proxy" method.

C. Allocation of Long-Term Contract Shortfalls

PG&E believes that wholesale customers should be allocated their portion of the Long-Term Contract Shortfall (or GC-2 shortfall). DRA argues against such an allocation because DRA observes that there is no reciprocal relationship between PG&E and its wholesale customers, i.e., if PG&E's wholesale customers were faced with their own marketing difficulties, PG&E would not have to pay any part of the wholesale customers' shortfall. DRA argues that equitable treatment requires no allocation.

PG&E counters this argument by stating such a position could be used to argue that every cost PG&E allocates to wholesale customers should be allocated elsewhere. PG&E concludes that the wholesale class, which is no more or less responsible for the GC-2 shortfall than PG&E's remaining non-GC-2 customers, should continue to be allocated its share of the GC-2 shortfall.

TURN also objects to the wholesale class being excluded from its allocation of GC-2 contract shortfalls.

We do not find DRA's arguments compelling on this issue. We will adopt PG&E's approach and continue to allocate a portion of the long-term contract shortfall to the wholesale class.

D. Weighted Customer Allocation Factors

PG&E proposes that the weighted customer allocation factors be developed without using any discount adjustment. On the other hand, DRA recommends that the discount adjustment factor be applied to the weighted customer allocation factors. PG&E rebuts this by stating that the customer charge, which is determined using the weighted customer allocation factors, cannot be discounted. For this reason, PG&E argues that the weighted customer allocation factors should assume no discounting. In addition, PG&E points out that the discount adjustment factor was not used for this purpose in the PG&E's last ACAP.

TURN objects to any alterations of the customer weighting factors at all.

We agree with PG&E on this issue and will not apply the discount adjustment factor to the weighted customer allocation factors.

Necessary to this calculation is a forecast of the number of customers in several classes. Both PG&E and DRA prepared forecasts which were very close together. We will adopt PG&E's forecasts as follows: 3.122 million residential individual meter customers; 88,599 residential master meter customers; and 198,323 commercial and industrial customers.

E. Incorporation of the Discount Adjustment Calculation

PG&E uses its discount adjustment factor to derive adjusted throughput, which it then uses to allocate costs. DRA has attempted a new approach this year. DRA's method takes the amount of revenue that the discount adjustment calculation indicates can be obtained from the noncore, and allocates that amount to the noncore. DRA then allocates the remaining costs to the core, UEG, and wholesale groups.

We will adopt PG&E's approach. While DRA's approach has conceptual merit, we believe it is not sufficiently developed to be used this year.

VII. Revenue Requirement

A. Overview

The Comparison Exhibit (Exhibit 74) sets forth the revenue requirements of DRA and PG&E based on adoption of each case. DRA's projected total revenue requirement is $2,932 million, which is slightly less than PG&E's total of $2,976 million. Based on the issues resolved and resulting numbers adopted in this decision, we adopt today a total revenue requirement of $2,859 million.

There are a few unresolved areas that impact the revenue requirement which have yet to be discussed. They will be addressed below.

B. EOR and Interutility Credits

The Comparison Exhibit shows different amounts for DRA and PG&E in this category. Since we have adopted an interutility throughput forecast of 460 million therms which is different than that proposed by any party, the adopted interutility credit will be different, namely $5.059 million.

C. LUAF and GDU Gas

Shrinkage is the cost of lost and unaccounted for (LUAF) gas and gas used by the gas department. In the Comparison Exhibit, PG&E forecasts $51.750 million of expenses associated with shrinkage for this ACAP period, while DRA estimates $49.935 million. Since these forecasts are based on the throughput forecasts and cost of gas forecasts of each party, neither of which we adopted in its entirely, we have calculated a slightly different forecast of $50.598 million.

D. CPUC Fee Expenses

PG&E and DRA forecasted slightly different CPUC Fee Expenses due to their different throughput forecasts. PG&E forecasts $3.884 million while DRA forecasts $4.004 million. (Comparison Exhibit 74, pp. 10 and 22.) The fee is .00076¢/therm associated with each therm of gas sold by PG&E, except for UEG, SCE-Cool Water, wholesale and interdepartment. Because of our adopted throughput of 5,473 MMth, the CPUC fee is forecasted to be $4.160 million.

E. Updating of Balancing Accounts

PG&E proposes to update its balancing accounts as of January 31, 1990. DRA has no objection to this one item of updating. We will not allow any other updating which is not reflected in the Comparison Exhibits (Exhibits 73 and 74.) PG&E should include its January 31, 1990 balancing account updates in its comments on the ALJ's proposed decision. The updates so provided are incorporated into the attached tables.

VIII. Rate Design Issues

A. Residential Rate Design

1. Residential Customer Charge

a. DRA's Position

DRA once again recommends that the residential rate structure be modified to include a $3 customer charge with revenues to be included in the baseline rate calculation. (Exhibit 37, p. 7-2.) DRA alleges this customer charge proposal is designed to further the Commission's policy of moving toward rates that reflect marginal costs of service. According to DRA, the average marginal cost based customer charge is $8.81. DRA believes the proposed charge would moderate bill impacts that would result from a rapid rate structure change. None of the participating parties at the hearing presented any contrary evidence on this point. Including the customer charge in the baseline rate calculation will have the effect of reducing the baseline rate. This will mitigate some of the associated negative bill impacts on low use customers, i.e., those customers whose usage is limited to their baseline allowance.

DRA points out that a residential customer charge is currently in effect for SoCal. DRA believes that with adequate customer education, this customer charge would be accepted by PG&E's customers.

b. Opposition to Customer Charge

Both PG&E and TURN oppose the imposition of a residential customer charge. TURN witness Marcus opposes the DRA recommendation due to a lack of customer acceptance and the adverse impacts that a customer charge would have on PG&E's summer pilot light turn-off gas conservation program. (Exhibit 52.) TURN also points out that the Commission, in PG&E's recent general rate case decision, rejected a similar DRA proposal with respect to PG&E's electric department. (D.89-12-057, pp. 257-58.) Both TURN and PG&E urge rejection of this proposal. In fact, TURN goes so far as to call it "misguided advocacy" on DRA's part.

c. Discussion

We agree with PG&E and TURN that the DRA proposal of a $3 residential charge is not persuasive at this time. As we recently stated in PG&E's rate case decision:

> "Our experience with SDG&E's customer charge, however, has dampened our enthusiasm. We now recognize that customer acceptance is a consideration that should outweigh economic correctness in evaluating the customer charge. Our fears about customers' reactions to a $3 customer charge have not been assuaged by DRA's suggestion that educational materials will improve acceptance of a customer charge. For these reasons, we will not adopt the customer charge recommended by DRA." (D.89-12-057, p. 258.)

DRA presented no arguments in this proceeding to alter our view as expressed in PG&E's recent rate case. We therefore reject DRA's proposal to institute a $3 customer charge.

2. Tier Differential Reduction

Both PG&E and DRA propose to reduce the tier differential between baseline and nonbaseline rates. PG&E recommends a 50% reduction from 40¢ to 20¢/therm. DRA proposes a more moderate 20% reduction, which TURN also supports.

All parties agree that the purpose of the reduction of the tier differential is to mitigate high bill impacts in cold winters. DRA argues its proposal is more in keeping with PU Code § 739, which was passed by the Legislature in reaction to the high gas bills of December 1987 and early 1988 and provides as follows:

> "The commission shall require that every electrical and gas corporation file a schedule of rates and charges providing baseline rates. The baseline rates shall apply to the first or lowest block of an increasing block rate structure which shall be the baseline quantity and shall be established for the residential consumption of gas and electricity. In establishing these rates, the commission shall avoid excessive rate increases for residential customers, and shall establish <u>an appropriate gradual differential between the rates</u> for the respective blocks of usage." (Emphasis added.)

Both DRA and TURN argue that the 20% reduction is more gradual and more equitable than PG&E's proposal. DRA argues that PG&E's proposal would have an adverse impact on baseline customers. According to DRA, 43.3% of customers would see bill increases of more than 19.5% under PG&E's plan. DRA points out that if the PG&E's proposal is adopted, customers at baseline amounts will receive a 24.7% increase, whereas customers who are above baseline would experience a 10% decrease. DRA cites PG&E's witness Smith for the proposition that a customer exactly at the baseline quantity would experience a $10.61 increase in the winter time. (Exhibit 1, pp. 8-23.)

PG&E counters by stating that DRA's proposal is too tentative, arguing its own proposal ameliorates the high bill concerns more effectively. Further, PG&E states the new Low Income Ratepayer Assistance (LIRA) program is intended to address the concerns of low income gas customers.

We agree with DRA and TURN that a 20% reduction in the tier differential is a more appropriate step at this time. We note that we recently approved a 25% electric tier differential reduction in PG&E's recent rate case. (D.89-12-057, pp. 262-63.) However, we believe that since the overall rate increase for the residential class is somewhat greater in this proceeding, a 20% tier differential reduction is the maximum we will approve today.

3. Low Income Ratepayer Assistance (LIRA)

We will discuss all issues raised in this proceeding related to the LIRA program in this section. In D.89-09-044, the Commission adopted a program providing for a LIRA rate structure set at 85% of the rate level of the pre-surcharge standard residential rates. The shortfall between what would be collected if LIRA customers paid full rates and what will be collected from them under the LIRA program is allocated to all customers except LIRA customers, UEG, cogeneration, wholesale, and customers with special contracts containing a specified rate. (D.89-09-044, p. 23.)

a. PG&E's Position

PG&E proposes to calculate the 15% LIRA reduction, set LIRA rates, and then incorporate the LIRA surcharge back into rates. PG&E opposes DRA's proposal to show the LIRA surcharge as a separate item on each customer's bill, arguing that D.89-11-018 gives PG&E the option to choose. Secondly, PG&E points out that many programs are implemented by the Commission which require the allocation and/or reallocation of costs yet none is displayed as separate line items on customer bills.

As to the LIRA administrative expenses, PG&E forecasts $1.4 million for the ACAP test period. PG&E estimated its LIRA volumes by multiplying the residential individual meter and master meter customer forecasts by appropriate factors. Finally, PG&E followed the standard practice of including shrinkage volumes when amounts are allocated on a equal cents per therm basis.

b. DRA's Position

DRA recommends that the LIRA surcharge be a separate line item on each customer's bill. In its reply brief, DRA acknowledges that D.89-11-018 does in fact grant the utility the right to choose. DRA points out that D.89-11-018 goes on to state that if the utility chooses not to itemize the LIRA program, the utility must still notify the ratepayers of the cost of the LIRA program through bill inserts. (D.89-11-018, p. 5.)

DRA now accepts PG&E's forecast of the LIRA administrative costs to be $1.4 million. DRA suggests that the $1.4 million should be put into rates subject to refund in the event the amounts are found to be unreasonable. (D.89-09-044, p. 24.) DRA also agrees that shrinkage volumes be included in cost allocation.

DRA continues to disagree with PG&E's method of calculating LIRA volumes. DRA develops its estimate by multiplying its residential throughput forecast by the ratio of LIRA throughput to residential throughput developed in the LIRA decision.

c. Discussion

We agree with PG&E that the choice is up to it whether or not to show the LIRA surcharge as a separate line item on its bill. Likewise, we need not repeat here the directives we gave PG&E in D.89-11-018 regarding customer notification. We expect PG&E has and will comply with that order until advised otherwise.

DRA and PG&E have reached agreement on a forecast of LIRA expenses of $1.4 million. Like other expenses of PG&E during the test period, these will be subject to examination in a reasonableness review. There is no special need to specify these particular funds as subject to refund.

In addition, since the parties now agree that shrinkage volumes should be included in cost allocation, we adopt PG&E's method for doing so.

Finally, as to calculation of LIRA volumes, we find PG&E's arguments more persuasive and adopt that method. Since we have adopted a different gas throughput forecast than that of PG&E or DRA, CACD has prepared its own calculation for the purposes of the rate tables attached to this decision.

B. Commercial Rate Design

The only change to commercial rate design proposed by PG&E is the introduction of two experimental schedules, G-NGV1 and G-NGV2, to be applicable to the sale of natural gas for use as a motor vehicle fuel. No party opposes this recommendation. We will adopt these rates as proposed by PG&E, including the implementation of a memorandum account to track revenues generated by the two schedules.

DRA proposes to set the transportation rates on G-NR3 equal to the average of the G-NR1 and G-NR2 transportation components. PG&E opposes DRA's proposal arguing that the purpose of Schedule G-NR3 is to unbundle service to allow large commercial customers to purchase transportation and procurement services separately. PG&E concludes that the transportation rates of G-NR3 should equal the transportation component of G-NR2, the bundle rate for large commercial customers. We agree with PG&E because DRA's proposal would harm the comparability of G-NR2 and G-NR3.

C. Industrial Rate Design

Combination of Rate Schedules G-P2B and G-IND

PG&E proposes to combine its current rate schedules for G-P2B and G-IND into a new rate, G-NCT. PG&E argues that the rates of G-P2B and G-IND would be very similar, based on cost of service information. PG&E asserts that the load patterns of the two groups are very similar. PG&E views the combination of the rate structures as providing additional simplicity in PG&E's rate structure.

Both DRA and FEA oppose the combination of these schedules. These parties believe the load and cost of service characteristics between the two customer groups are different enough to warrant separate schedules.

FEA points out that PG&E did not provide a separate calculation of the cost of serving customers on these two schedules in its original filing. In response to a FEA data request, PG&E provided data that shows the average cost associated with Rate G-P2B is 16.122¢ per therm, while the average cost associated with G-IND is 13.374¢ per therm (Exhibit 64.) FEA points out this is a difference of 20%.

DRA's witness Auriemma argued the basis for maintaining the separate identity of these rate schedules is because of differing load and cost characteristics, varying cost of service between the two groups and noting the G-P2B customers are smaller than G-IND customers (RT 924).

We agree with DRA and FEA that PG&E has failed to make a persuasive showing that customers will be better served by a combined rate schedule such as it has proposed. We are convinced that the cost of service and other differences between these two groups justify the continuation of separate schedules at this time.

D. Cogeneration Rate Design and the Cogeneration Shortfall Account

TURN, based on a proposal in the SoCal ACAP, proposed the following change to the basis of setting UEG parity rates for cogeneration customers:

> "PG&E has indicated that it has no objection to the SoCalGas proposal to fix the cogen parity rate on a forecast basis equal to the forecasted average UEG rate for the ACAP period, eliminating the current 60-day true-up procedure. I agree that such a change would have merit. The existing formula can create significant hardships and anomalies when UEG

> customers are curtailed or voluntarily switch to fuel oil. The SoCal proposal offers at least a partial resolution of these problems, although a more complete remedy would also require that avoided cost payment calculations likewise utilize the same average UEG gas cost. Once this change is implemented the Cogen Shortfall Account should be eliminated." (Exhibit 51, pp. 24-25.)

In its opening brief, DRA joins in this recommendation. DRA notes the current average cogeneration transportation rate is based on the recorded average UEG gas rate lagged by two months. The new proposal calls for the cogeneration transportation rate to be based on the forecasted average UEG rate.

Likewise, PG&E, while taking no position on the issue during hearings, has no objection to adoption of the forecast approach.

The only party expressing opposition to this change is CCC in its reply brief, arguing that the issue is not properly before the Commission at this time since PG&E took no position on the issue in hearing. However, CCC failed to question TURN's witness on its testimony on this matter.

While it is appealing to remain consistent with policies adopted in the SoCal ACAP, in this instance we find that substantial differences do exist between the SoCal service territory and the PG&E service territory. In the SoCal service territory, prolonged UEG curtailments caused CCC to propose the forecasted method which in the current case they are opposing. PG&E has not been forced to curtail as widely as SoCal, so we are not persuaded that it is necessary to adopt the forecasted rate. In addition, we note that the avoided cost payment calculations currently employ the actual lagged rate calculation. By continuing our current system, we assure consistency between payments and cost calculations. We therefore find merit in the substance of CCC's arguments and decline to adopt the forecasted rate.

With respect to CCC's arguments relating to procedure, we remark that CCC was unpersuasive. Merely because PG&E took "no position" on this issue in hearing does not mean we are constrained from adopting it.

Merely because PG&E took "no position" on this issue in hearing does not mean we are constrained from adopting it. TURN put the issue before the Commission in direct testimony in this proceeding so CCC was on notice as to possible Commission action on this topic. In addition, we find Mojave's objections raised for the first time in its comments on the proposed decision equally unpersuasive.

In light of this change, we now can turn to the issue of the elimination of the Cogeneration Shortfall Account (CSA). The CSA tracks any shortfall in transportation revenues that may occur from customers receiving transportation service under the G-COG rate schedule. G-COG customers are charged for transportation service at the lower of: the average PG&E UEG transportation rate, lagged by two calendar months; or their otherwise applicable schedule which would apply if the customer did not have any cogeneration equipment.

DRA, TURN, and PG&E all support elimination of the Cogeneration Shortfall Account if we adopt a forecasted cogeneration rate. However, TURN also recommends that the existing balance in the CSA should not be included in rates until the DRA auditors have an opportunity to determine the reason for the shortfalls. The amount in question is approximately $465,000. DRA supports TURN's suggestion of an audit prior to recovery. Not surprisingly, PG&E opposes any further audit of CSA rates.

We agree that the time to eliminate the CSA is here. Even if the forecasted rate is not adopted, as we stated in the SoCal ACAP, "It has not worked as intended, and is not likely to work as intended under any reasonably foreseeable set of circumstances." (D.90-01-015, pp. 75-76.) Likewise, we agree that further auditing is in order as suggested by TURN and DRA. Therefore, the amount should not be recovered in rates at this time. DRA should complete its audit as part of PG&E's next ACAP proceeding.

IX. Other Proposals Rejected At This Time

A. Overview

Several parties proposed changes to cost allocation, rate design, or risk allocation which have not yet been addressed. These proposals have in common the fact each of them drew vociferous opposition from other parties. Also, each of these proposals was the subject of a motion to strike by at least one party.

Since the hearings in this case, we have issued two decisions that relate to the overall gas industry structure. Had these decisions been issued before the ALJ's rulings on the motions to strike, the outcome would perhaps have been different. The first decision, issued January 9, 1990, sets forth an agenda and procedural schedule to consider cost allocation and rate design policy issues for gas utilities. The stated goal is to develop a ratemaking methodology which is based on long-run marginal costs. (D.90-01-021, p. 1.)

On February 7, 1990 we issued an Order Instituting Rulemaking which seeks to change the structure of gas utilities' procurement practices for the noncore market and solicits proposals for balanced incentives to provide efficient procurement and transmission service to all customers. The Commission views this rulemaking as a companion to D.90-01-021, stating that "...these two orders comprise the Commission's initiative in response to the mid-course evaluation of its natural gas program which began with an en banc hearing on November 1, 1989." (R.90-02-008, p. 1.)

In light of these two recent decisions we are rejecting the following proposals at this time. The Commission has set forth more appropriate forums for each of them to be raised. For this reason, our summary of the issues will be quite brief in this decision. We note that some parties spent inordinate time on these issues in their briefs, both pro and con. If parties continue to espouse any of these proposals we hope they consider carefully the arguments raised against them and work towards refining their proposals before bringing them before us in another forum.

B. PG&E's Fuel Price Correction Mechanism

PG&E proposes the adoption of a Fuel Price Correction (FPC) mechanism. PG&E contends that this mechanism would simplify the ACAP process by de-emphasizing the importance of gas and alternative fuel price forecasts and would focus PG&E's risk on its marketing efforts. PG&E proposes the FPC mechanism to work as follows: each year the discount adjustment model would be rerun using readily available historic data for the most recent 12-month period. That calculation would determine how much PG&E could have collected in noncore transportation revenues, given the actual commodity gas and alternative fuel prices which existed during that time period. Under the FPC mechanism, if PG&E could have collected more than was originally forecast for that period because of unanticipated price movements, then PG&E would be required to return money to all of its customers on an equal cents per therm basis.

Likewise, if gas and alternative fuel prices were such that PG&E could not have collected the forecasted amount of revenue, PG&E would be allowed to recoup the difference in its next ACAP.

DRA, TURN, and FEA all oppose adoption of the FPC mechanism. First, these parties argue that the FPC mechanism would substantially minimize the economic stake for PG&E to maximize its efforts to keep the total burnertip price of gas competitive with other fuels. They believe this is contrary to Commission policy which intended to put gas utilities at some economic risk as part of the restructuring of the gas industry. They allege that the FPC mechanism essentially insulates PG&E against changes in oil and gas prices. Second, the parties disagree that the ACAP process would truly be simplified by the FPC mechanism. Forecasts of gas and oil would still have to be made to input the econometric sales forecast. The FPC mechanism would add an additional step of having to true-up the prior year's forecast. Third, the FPC mechanism cannot accurately reflect the true oil and gas prices that PG&E's alternate fuel capable users pay because PG&E does not know what those prices are. The average prices used in the FPC mechanism may or may not be close to reality.

As we stated earlier, in light of the pending generic Commission proceedings we decline to adopt the FPC mechanism at this time. However, we commend PG&E's effort to attempt to simplify the ACAP process through its FPC mechanism proposal. We will give due consideration in our upcoming rulemaking, R.90-02-008. We urge PG&E to continue refining a method for implementing the FPC mechanism since some questions arose during hearings regarding the use of a different time period to calculate the FPC than the April through March ACAP forecast period.

C. CIG/CLFP's Single Volumetric Rate Proposal

CIG/CLFP also argues its proposal would simplify the ACAP process and improve PG&E's rates through (1) the introduction of a single component rate, volumetrically based and seasonally differentiated and (2) the elimination of exit costs. CIG/CLFP's experience is that the current multi-component default transportation and exit costs are far too complex to signal any meaningful distinctions to PG&E's end users. CIG/CLFP asserts that the present system does not permit customers to easily forecast their future gas costs and thus, does not permit them to readily compare projected gas costs with projected alternate fuel costs for purposes of choosing their most economic fuel.

PG&E and DRA both oppose CIG/CLFP's proposal. PG&E alleges that since a majority of its costs are fixed, all volumetric noncore transportation rates would not accurately reflect PG&E's costs. DRA argues that this proposal is completely contrary to the Commission's new regulatory program for the gas industry. The proposal by CIG/CLFP for a single volumetric rate would eliminate the customer charge, the D1 and D2 demand charges, and the existing volumetric charge.

DRA claims that large alternate fuel capable customers, such as the members of CIG/CLFP, love the flexibility to skip on and off gas, but they do not like the modest burden of demand charges which apply for 12 months. DRA asserts that demand charges are really a way of signaling to users their costs of having the utility's distribution system being in place and ready and able to serve the industrial customer when the customer makes the "demand" for service. DRA believes these types of customers should not be encouraged, through rate design, to have the flexibility to fuel switch for short periods of time without some contribution towards the fixed costs of the distribution system, and its availability to serve them when they request it.

Likewise, we agree with DRA and PG&E that this is not the appropriate time to make an alteration in noncore rate design of this magnitude. In D.90-01-021, we stated that Phase 3 of that proceeding will address rate design policy issues. CIG/CLFP may raise its proposal in that forum.

D. FEA's Proposal to Establish a Differing Transport Component for Residential and Commercial Classes

FEA proposes that the transportation rate for residential and commercial customers should not be identical based on cost of service evidence. FEA argues it is undisputed that there is a significant difference in the cost of serving residential customers and that of serving the various commercial classes of customers. FEA claims the policy of charging the same transportation rate component for both residential and commercial customers results in commercial customers being significantly overcharged. FEA believes this is a rate design issue that the Commission could act on now, without violating PU Code § 739.6 which provides as follows:

> "The Commission shall establish rates using cost allocation principles that fairly and reasonably assign to different customer classes the costs of providing service to those customer classes, consistent with the policies of affordability and conservation. The cost allocation methodology adopted for gas corporations by the Commission in Decisions 86-12-009 and 86-12-010, as supplemented by Decisions 87-05-046 and 87-12-039, is

> consistent with this policy, and shall be retained by the Commission at least until December 31, 1990, except that the Commission may modify this cost allocation methodology to address customer hardships and inequities if residential customers as a class are not, on balance, adversely affected and the purpose of the modification is not solely protection of gas corporation revenues. If any gas corporation files a cost allocation application seeking to change that methodology after May 1, 1990, the Commission may not issue an order on that application until January 1, 1991."

TURN, on the other hand, argues that FEA's proposal is exactly the kind of cost allocation change PU Code § 739.6 intended to prohibit until January 1, 1991.

After studying the legal arguments of both parties, we concur with TURN that the FEA proposal is prohibited at this time by PU Code § 739.6. However, we note that the upcoming cost allocation and rate design proceeding (D.90-01-021) is the appropriate forum for FEA to present its proposal.

E. <u>CPG's Transport Fee Proposal</u>

CPG proposes that the Commission adopt an unbundled third-party transport fee to be assessed on volumes of third-party transportation - only gas moved on the PG&E system. CPG believes this transport fee would represent an allocation to third-party transportation customers of the new increases in costs PG&E has incurred to make third-party transportation possible.

Salmon/Mock is most vocal among the parties in its opposition to CPG's proposal. Salmon/Mock argues that CPG failed to make a showing that any increased costs which may have arisen due to the changeover to a new gas regulatory structure are due solely or are even primarily associated with third-party transportation of gas.

Salmon/Mock also argued that a generic proceeding is a more appropriate forum. We agree that this cost allocation issue should likewise be referred to the proceeding set forth in D.90-01-021.

There is one evidentiary issue that remains dangling that arose over CPG's proposal. Parties were instructed to brief the admissibility of Exhibit 57, which Salmon/Mock attempted to introduce for the stated purpose of "impeaching" CPG's position on the transport fee. CPG objects to the admissibility because Exhibit 57 relates to the position taken by a different trade organization, the Canadian Petroleum Association (CPA). While admitting that several of its members are also CPA members, CPG argues it is irrelevant to this proceeding.

At hearings, the ALJ initially sustained CPG's objection to admissibility due to a lack of adequate foundation. After reviewing the arguments in the briefs, we agree with that tentative ruling and will not admit Exhibit 57 in evidence. We note that since we have rejected CPG's proposal anyway, Salmon/Mock is not harmed by this ruling.

F. TURN's AGR Proposal

As a secondary proposal, if its rates in effect approach was rejected, TURN recommended the adoption of an AGR that would operate in a manner parallel to the electric Annual Energy Rate, passing through to the balancing account only 80% of the difference between forecasted and actual core gas costs. TURN states PG&E would be at risk for the other 20% of the deviation from the adopted forecast.

TURN's AGR proposal received the most opposition (based on pages of briefs) of any issue in this proceeding. The APMC, who did not participate in hearings, filed a 40-page brief devoted solely to attacking this proposal. In addition, Salmon/Mock, CPG, and DRA all reject TURN's AGR.

Thankfully, we will not have to summarize all the opposition because we have already created a forum which will specifically address the AGR, namely the recently issued

Rulemaking, R.88-02-008 (pp. 15-17). Due to its placement in that proceeding, we will not adopt an AGR at this time.

X. Workshops to Streamline the ACAP Process

In light of our two recent gas decisions discussed in the preceding section, we realize that 1990 will be a hectic year for the parties who participate not only in individual ACAPs, but the generic proceedings as well. As we stated in D.90-01-021, we "plan to continue the trend from 1989 and restrict this year's ACAPs to only routine, non-policy cost allocation and rate design issues." (D.90-01-021, p. 5.)

We have already ordered CACD to convene workshops on the discount adjustment methodologies for use in the 1990 ACAPs. Likewise, we believe the parties would benefit if those workshops were expanded to include other issues to streamline the ACAP process. We therefore direct CACD to set workshops and send an agenda at least seven days in advance to all parties to this proceeding and the SoCal/SDG&E ACAP parties as well. CACD will advise parties of such workshops in the near future.

XI. TURN's Request for Finding of Eligibility for Compensation

We will issue a separate decision on TURN's request that it be found eligible for intervenor compensation under Rule 76.54(a) of the Commission's Rules of Practice and Procedure.

XII. Transcript Corrections

TURN and Salmon/Mock set forth proposed transcript corrections in their opening briefs. We accept these requested changes. They will be made in the Commission's official transcript of the proceeding.

Findings of Fact

1. Determining the appropriate forecast of the cost of gas for a utility in its ACAP proceeding is an important piece of the new gas industry structure.

2. PG&E forecasts its Southwest short-term or spot prices using three independent forecasting methodologies.

3. PG&E concludes that the appropriate volume weighted Southwest spot gas price forecast at the California border for the test period is $2.48/Dth.

4. In order to forecast the cost of spot gas from Southwest supplies, DRA employs a methodology making a straight-line projection of the prices at the California border (which include all transportation and other charges incurred to get the gas to the border).

5. DRA chose to update this figure to include prices from September and October 1989 in Exhibit 38, which was presented for the first time at hearings.

6. The Exhibit 38 update results in an insignificant difference in the bottom line Southwest spot gas price and the resulting WACOGs.

7. The mistaken strategy call to put forward Exhibit 38 should not serve to reject the merits of DRA's otherwise reasonable approach embodied in Exhibit 37. We find DRA's approach more persuasive and frankly more straightforward than the average of the three forecasts propounded by PG&E.

8. PG&E adds a $0.05/Dth differential to the cost of long-term Southwest supplies in order to reflect the security of supply and take-level flexibility associated with these long-term supplies.

9. DRA objects to a $0.05/Dth premium above the spot price being included in the forecast. DRA argues that while it may be

true that purchasers of contract gas obtained some benefits as a result of the contracting arrangement, producers of gas also benefit by the contracting arrangement.

10. We concur with DRA's analysis that the benefits of these long-term supply contracts flow to both producers and purchasers. Since the benefits flow both ways it does not seem reasonable to expect a premium to be paid.

11. PG&E forecasts for the test period an average price of $2.07 at the California border when converted from wet to dry and when other charges are included. PG&E argues that Southwest supply prices are viewed as a significant pricing factor by Canadian and California producers.

12. DRA recommends no increase in the price of gas from Canada be included in the ACAP forecast.

13. TURN has recommended that the Commission abandon any attempt to forecast gas prices and instead rely on "rates in effect."

14. Both DRA and CPG support the principle behind TURN's "rates in effect" proposal.

15. The "rates in effect" proposal has particular appeal in forecasting the Canadian price.

16. Our overriding desire is to remain neutral on the subject of whether Canadian prices should increase or decrease and truly allow PG&E an opportunity to negotiate aggressively without giving its producers a signal that California is expecting a price increase of a certain amount.

17. In light of the recent FERC PGT general rate case decision, PG&E's forecast of $2.07 for Canadian supplies is reasonable.

18. For this ACAP test period PG&E forecasts that the California gas price will average $2.03/Dth.

19. PG&E notes that no intervenor has opposed PG&E's California volume forecast of 92,323 MDth for the test period.

20. Both TURN and DRA once again argue that the current price be used for the forecast period for California gas. That price would be $1.85/Dth.

21. We are persuaded by DRA's and TURN's position regarding California supplies. It is not our intention to be punitive by not predicting a price increase. We hope to send a clear signal to the California market that our goal is to allow PG&E to negotiate aggressively to obtain the lowest possible prices for its end users.

22. PG&E forecasts that the Rocky Mountain price will average $1.95/Dth at the California border during the test period.

23. DRA adopted PG&E's Rocky Mountain price forecast for the test period.

24. TURN consistently recommends that the Rocky Mountain price be held to the existing rate. TURN recommends that this rate should be about $1.75/Dth.

25. PG&E proposes equivalent percentage sequencing between Canadian and Southwest supplies beginning in July of 1990. PG&E asserts that the resulting Canadian and Southwest volume forecasts for the test period are 295,015 MDth and 157,967 MDth, respectively.

26. DRA maintains that PG&E's sequencing decisions, whatever they are during the forecast period, should be subject to review in a reasonableness proceeding.

27. DRA acknowledges that because gas prices could vary from the forecasts adopted in this proceeding, PG&E should retain flexibility in its sequencing decision-making process.

28. Salmon/Mock's proposal that a certain amount of capacity on the PGT system should be set aside for transport-only customers is irrelevant to an ACAP proceeding.

29. PG&E is accountable for its gas purchases and volumes in its reasonableness review.

30. We encourage PG&E to make available unneeded capacity for transport-only customers on the PGT system but doing this must be in keeping with PG&E's first priority to operate its gas system for the benefit of PG&E's core customers.

31. PG&E and DRA are in agreement on the $177.778 million stated by PG&E in this ACAP period for (1) the demand charge for Canadian gas, (2) the PG&E cost of service charge, and (3) the El Paso demand charge.

32. DRA accepts PG&E's estimates that monthly storage-related transition costs which, according to D.87-12-039 were to be subtracted from the cost of gas, will be zero in this ACAP period.

33. PG&E estimates liquids settlement direct bills to total $6.8 million for the test period. DRA accepts this amount.

34. PG&E seeks recovery in this ACAP proceeding of $18.6 million in El Paso's Account No. 191 direct bill costs.

35. DRA estimates the Account No. 191 costs, as adjusted by anticipated offsetting revenues, to be approximately $6 million for this ACAP test period..

36. PG&E recommends an offset of $48 million based on the Chevron and Southland settlements.

37. DRA recommends that these Account No. 191 amounts not be included in rates for this ACAP period, but instead be tracked for recovery, with interest and recovered in the next ACAP period. DRA cites the pending legal challenges to the amounts in this account as a reason to postpone including these amounts in rates.

38. CIG/CLFP views the Account No. 191 amounts as unrecovered purchased gas costs that do not meet the Commission's definition of transition costs as laid out in D.87-12-039.

39. CIG/CLFP has raised some interesting arguments as to whether these are properly "transition costs" under Commission definitions. However, we need not reach that issue today.

40. DRA accepts the PG&E forecast of inventory conditions at the beginning of the ACAP period. The forecasted value is $2.12/Dth with the forecasted volume of 65,877 MDth.

41. DRA calculates the monthly carrying costs to be a total of $14.163 million for the ACAP period, using the DRA forecast of gas prices.

42. In January 1990, the Commission issued D.90-01-015 in the SoCal ACAP proceeding, which extensively discussed the background and appropriate resolution of the take-or-pay allocation issue.

43. The arguments of the parties on take-or-pay cost allocation are virtually the same as those raised in the SoCal ACAP.

44. PG&E and DRA agree on the amount of take-or-pay costs at issue in this case, namely, $64.8 million.

45. PG&E is opposed to the adoption of any method that places its shareholders at risk for these costs, or requires them to absorb some portion of them.

46. The allocation method recommended by DRA is the same method it proposed in the SoCal ACAP and which was adopted by the Commission. DRA recommends a method that is similar to the equitable sharing mechanism provided for by the FERC in its Order No. 500.

47. For consistency's sake, DRA believes the same equitable sharing mechanism should be adopted for PG&E with the caveat that the collection of these take-or-pay costs should be made subject to refund.

48. The parties have not persuaded us that we should alter the careful and considered analysis and conclusion we reached on this issue in the SoCal ACAP.

49. However, in light of the recent AGD decision we will make the amount of take-or-pay costs put into rates under DRA's proposed mechanism subject to refund.

50. PG&E forecasts an average price of $17.78/Bbl for the U.S. Refiner's Average Acquisition Cost of imported crude oil for the ACAP forecast period.

51. DRA acknowledges, however, that the difference between DRA and PG&E forecast is so small as to be insignificant. The PG&E yearly average imported RAAC of $17.78/Bbl compares to the DRA yearly average of $17.63/Bbl.

52. PG&E forecasts the wholesale and retail prices for No. 6 low sulfur fuel oil to be 23.3¢/th and 27.9¢/th, respectively.

53. PG&E forecasts wholesale and retail prices for No. 2 distillate to be 37.6¢/th and 41.2¢/th, respectively.

54. PG&E forecasts wholesale and retail prices of propane to be 39.2¢/th and 51.7¢/th, respectively.

55. We adopt an alternate fuel price for refineries of 33.9¢/th for use in the discount adjustment calculation.

56. Both DRA and PG&E developed econometric throughput forecast for the residential, commercial, industrial, steam heat, interdepartmental, and gas department use classes of service as well as for LUAF gas volumes.

57. PG&E forecasts a residential throughput of 2,129 MMth, and the commercial throughput of 867 MMth. DRA's forecasts are very close being 2,159 MMth for the residential class and 843 MMth for commercial throughput.

58. PG&E has forecasted 1,512 MMth of industrial throughput. PG&E derives this number from the econometric model forecast of 1,743 MMth, from which two items are subtracted.

59. 181 MMth are subtracted to capture the effect of the transfer of industrial load from the industrial throughput forecast to the cogeneration forecast.

60. PG&E has subtracted 50 MMth to reflect the fact that the usage at Chevron's Richmond Refinery will be less than the historic use embedded in the industrial throughput data because of the recent fire at the refinery.

61. DRA's estimate for industrial throughput as set forth in the comparison exhibit is 1,582 MMth.

62. As set forth in the comparison exhibit, TURN is recommending an industrial throughput of 1,638 MMth.

63. PG&E's and DRA's interdepartmental, gas department use, and LUAF throughput forecast are identical. They are as follows: interdepartmental use is 3 MMth, gas department use is 60 MMth, and LUAF is 169 MMth.

64. As to the steam heat throughput, DRA estimates 11 MMth while PG&E estimates 10 MMth.

65. Both parties forecast 602 MMth of cogeneration throughput (Rate Schedule G-COG) and 358 MMth of EOR throughput.

66. PG&E and DRA also agree on a wholesale throughput forecast of 112 MMth.

67. Since both DRA and PG&E agree that there will be 231 MMth of industrial GC-2 throughput, the parties agree to 119 MMth of cogeneration GC-2 throughput during the ACAP forecast period.

68. PG&E's electric department is the largest single user of natural gas in PG&E's service territory. PG&E and DRA have reached agreement on a forecast on 1,309 MMth. In addition, PG&E and DRA agree on a forecast of start up fuel of 13 MMth during the test period.

69. PG&E has forecasted that the baseload of the Cool Water plant will be 38 MMth for the ACAP test period.

70. DRA based its forecast upon the results of the ELFIN production cost model, and incorporates the generation resource mix assumptions that parties have settled on in the latest SCE ECAC proceeding (A.89-05-064). The DRA forecast for SCE demand is 120 MMth.

71. The interutility throughput forecast is clearly the most controversial throughput forecast in this ACAP proceeding.

72. PG&E recommends that an interutility throughput of 90 MMcf/day or 345.79 MMth be adopted for the test period based on historical interutility throughput level.

73. DRA's forecast for interutility throughput is substantially higher than PG&E's. DRA projects test period throughput for interutility transport to be 600.038 MMth for an average of 168 MMcf/day.

74. TURN forecasts interutility throughput to be 1,038.75 MMth or an average of about 275 MMcf/day. This throughput is higher than either DRA's or PG&E's.

75. SoCal supports PG&E's estimate of 90 MMcf/day in this ACAP period.

76. The number selected in the SoCal ACAP was a number that had not been recommended by any one party. The lesson we conclude from our SoCal ACAP decision is that it is appropriate to pick a number somewhere in between those recommended by the parties when it is such a qualitative judgment call.

77. We are unconvinced that DRA truly took into account all of the factors which PG&E says are necessary to weigh in attempting to forecast interutility throughput.

78. None of the throughput forecasts proposed by the parties is particularly persuasive.

79. The purpose of discounting rates is to retain customers who are unwilling to pay tariff rates, but who are willing to pay rates that are high enough to make a contribution to fixed costs.

80. Both PG&E and DRA essentially used the same discount adjustment model that was adopted in the last ACAP decision.

81. TURN has modified its original proposal and in this proceeding is now recommending an all econometric model, termed the Miller approach after the SoCal witness who sponsored such an approach in the SoCal ACAP.

82. PG&E proposes several modifications to the structure and to the inputs of the discount adjustment model which impact the end

result. PG&E proposed to modify the model by: (a) establishing a customer group for refineries; (b) reducing the $0.02 gas premium to zero for refineries; and (c) excluding the D1 demand charge from the exit cost calculation.

83. PG&E comes up with a level of discounting of approximately 30% for its new proposed G-NCT Schedule and 11% for the G-COG Schedule.

84. DRA's objections to PG&E's modifications are threefold: (a) PG&E's estimate of the exit cost is erroneous; (b) PG&E understates the premium; and (c) the adopted discount adjustment should be no more than the level of discounting PG&E must make to retain load.

85. DRA proposes to include one-half of the D1 demand charge in the exit cost portion of the discount adjustment.

86. DRA's final recommendations of the discount adjustment factors are as follows: a 13% discount factor for the G-IND class, a 2.1% discount factor for the G-P2B class, and a 4.3% discount factor for the G-COG class.

87. Both PG&E and DRA use a discount adjustment method that is based on an estimation of the maximum rate a customer would be willing to pay. This rate, which is equal to the sum of gas cost, gas premium, and exit cost, is calculated for three customer groups using three types of alternate fuel.

88. PG&E and Chevron argue it is unreasonable to apply exit costs or the 2¢ gas premium to refinery loads.

89. The amount of discounting is assumed to be the percent difference between the maximum rate a customer group would be willing to pay and the default rate.

90. The reason PG&E and DRA reached different results is because PG&E does not include demand charges in its exit cost.

91. PG&E's discount adjustment factor of 30% is clearly out of line with historical trends.

92. The main philosophical difference between the methods used by PG&E and DRA and the TURN econometric method is that the former assumes that the customer's decision to use gas as a fuel is mainly dependent on the price of alternate fuel.

93. TURN and DRA's methodologies resulted in similar discount factors.

94. Based on the gas cost and throughput numbers adopted in this decision, CACD will have to produce new tables for our decision.

95. We find merit in the econometric proposal set forth by TURN and wish work on this area to continue.

96. We would prefer that a consistent methodology be employed for all three utilities.

97. One of our goals of this approach is to enable our own CACD to be able to implement a consistent methodology for the utilities.

98. Cost allocation involves the assignment of the authorized costs associated with the operation of the utility's system to the various customer classes for recovery through rates.

99. As evidenced by Part 2 of the Joint Comparison Exhibit (Exhibit 74), DRA and PG&E agree as to most of the allocating factors which should be used.

100. CACD has created its own cost allocation model which will be used to calculate the attached tables to this decision.

101. PG&E proposes that state and federal income taxes be allocated according to customer class.

102. In DRA's rate design, the DRA allocates total income taxes to functional groups based on the proportion of total rate base in each functional group.

103. We find using the same method for cost allocation and rate design to be superior to DRA's proposal.

104. PG&E believes that wholesale customers should be allocated their portion of the Long-Term Contract Shortfall. DRA

argues against such an allocation because DRA observes that there is no reciprocal relationship between PG&E and its wholesale customers.

105. PG&E proposes that the weighted customer allocation factors be developed without using any discount adjustment. DRA recommends that the discount adjustment factor be applied to the weighted customer allocation factors. We agree with PG&E on this issue and will not apply the discount adjustment factor to the weighted customer allocation factors.

106. PG&E uses its discount adjustment factor to derive adjusted throughput, which it then uses to allocate costs. DRA's method takes the amount of revenue that the discount adjustment calculation indicates can be obtained from the noncore, and allocates that amount to the noncore.

107. Since we have adopted an interutility throughput forecast of 460 million therms which is different than that proposed by any party, the adopted interutility credit will be different, namely $5.059 million.

108. In the Comparison Exhibit, PG&E forecasts $51.750 million of expenses associated with shrinkage for this ACAP period, while DRA estimates $49.935 million.

109. PG&E and DRA forecasted slightly different CPUC Fee Expenses due to their different throughput forecasts. PG&E forecasts $3.884 million while DRA forecasts $4.004 million.

110. PG&E proposes to update its balancing accounts as of January 31, 1990. DRA has no objection to this one item of updating.

111. DRA recommends that the residential rate structure be modified to include a $3 customer charge with revenues to be included in the baseline rate calculation.

112. Both PG&E and TURN oppose the imposition of a residential customer charge.

113. In PG&E's recent general rate case decision, the Commission rejected a similar DRA proposal with respect to PG&E's electric department.

114. DRA presented no arguments in this proceeding to alter our view as expressed in PG&E's recent rate case.

115. Both PG&E and DRA propose to reduce the tier differential between baseline and nonbaseline rates. PG&E recommends a 50% reduction from 40¢ to 20¢/therm. DRA proposes a more moderate proposal of a 20% reduction, which TURN also supports.

116. We agree with PG&E that the choice is up to it whether or not to show the LIRA surcharge as a separate line item on its bill.

117. DRA and PG&E have reached agreement on a forecast of LIRA expenses of $1.96 million.

118. As to calculation of LIRA volumes, we find PG&E's arguments more persuasive and adopt that method.

119. The only change to commercial rate design proposed by PG&E is the introduction of two experimental schedules, G-NGV1 and G-NGV2, to be applicable to the sale of natural gas for use as a motor vehicle fuel.

120. PG&E proposes to combine its current rate schedules for G-P2B and G-IND into a new rate, G-NCT.

121. Both DRA and FEA oppose the combination of these schedules. These parties believe the load and cost of service characteristics between the two customer groups are different enough to warrant separate schedules.

122. We decline to adopt the forecast approach from the SoCal ACAP for cogeneration gas rates. We prefer to remain with the current calculation based on actual UEG rates lagged 60 days. This approach continues to provide a reasonable basis for maintaining rate parity between cogenerators and UEG customers.

123. We find CCC's argument that because PG&E took "no position" on this issue in hearing we are constrained from adopting it to be unpersuasive. TURN put the issue before the Commission in

this proceeding so CCC was on notice as to possible Commission action on this topic.

124. DRA, TURN, and PG&E all support the elimination of the Cogeneration Shortfall Account if we adopt a forecasted cogeneration rate.

125. In light of the record from the SoCal ACAP, we agree that the time to eliminate the CSA is here, even though we do not adopt a forecasted cogeneration rate.

126. Therefore, the amount should not be recovered in rates at this time. DRA should complete its audit as part of PG&E's next ACAP proceeding.

127. Since the hearings in this case, we have issued two decisions that relate to the overall gas industry structure.

128. The first decision, issued January 9, 1990, sets forth an agenda and procedural schedule to consider cost allocation and rate design policy issues for gas utilities.

129. On February 7, 1990 we issued an Order Instituting Rulemaking which seeks to change the structure of gas utilities' procurement practices for the noncore market and solicits proposals for balanced incentives to provide efficient procurement and transmission service to all customers.

130. PG&E proposes the adoption of a Fuel Price Correction (FPC) mechanism. PG&E contends that this mechanism would simplify the ACAP process by de-emphasizing the importance of gas and alternative fuel price forecasts and would focus PG&E's risk on its marketing efforts.

131. CIG/CLFP also argues its proposal would simplify the ACAP process and improve PG&E's rates through (a) the introduction of a single component rate, volumetrically based and seasonally differentiated and (b) the elimination of exit costs.

132. FEA proposes that the transportation rate for residential and commercial customers should not be identical based on cost of service evidence. FEA claims the policy of charging the same

transportation rate component for both residential and commercial customers results in commercial customers being significantly overcharged.

133. We concur with TURN that the FEA proposal is prohibited at this time by PU Code § 739.6. The upcoming cost allocation and rate design proceeding (D.90-01-021) is the appropriate forum for FEA to present its proposal.

134. CPG proposes that the Commission adopt an unbundled third-party transport fee to be assessed on volumes of third-party transportation - only gas moved on the PG&E system.

135. Salmon/Mock attempted to introduce Exhibit 57 for the stated purpose of "impeaching" CPG's position on the transport fee. CPG objects to the admissibility because Exhibit 57 relates to the position taken by a different trade organization, the Canadian Petroleum Association (CPA).

136. As a secondary proposal, TURN recommended the adoption of an AGR that would operate in a manner parallel to the electric Annual Energy Rate, passing through to the balancing account only 80% of the difference between forecasted and actual core gas costs.

137. In light of our two recent gas decisions (D.90-01-021 and R.90-02-008), we realize that 1990 will be a hectic year for the parties who participate not only in individual ACAPs, but the generic proceedings as well.

<u>Conclusions of Law</u>

1. We should adopt DRA's forecast for Southwest spot gas of $2.35/Dth because it is more straightforward and reasonable than PG&E's.

2. We should adopt a core WACOG of $2.14/Dth and a noncore WACOG of $2.36 based on the gas prices we have forecasted.

3. We should not adopt a $.05 premium for long-term Southwest supplies because both producers and purchasers benefit from the contracts.

4. We should adopt a "rates in effect" approach for Canadian and California gas supplies so that we do not send the wrong signals to gas suppliers.

5. Therefore, we should adopt a price of $2.07/Dth for Canadian gas supplies.

6. We should adopt a price of $2.03/Dth for California gas based on the "rates in effect" approach.

7. We should adopt a volume forecast of 92,323 MDth for California gas because it was unopposed.

8. We should adopt a price of $1.95/Dth for Rocky Mountain gas supplies and a volume forecast of 2,589 MDth.

9. It is reasonable to adopt Canadian volume forecasts of 295,015 MDth and Southwest volume forecasts of 157,967 MDth.

10. Pipeline demand charges of $177.778 million are reasonable and should be adopted.

11. An estimate of zero monthly storage-related transition costs should be adopted because PG&E and DRA are in agreement.

12. A liquids settlement direct bills estimate of $6.8 million should be adopted for the test period.

13. An offset of approximately $48 million should be adopted resulting from the Southland and Chevron settlements.

14. It is reasonable to postpone recovery of Account No. 191 costs because of pending legal challenges.

15. It is reasonable to adopt the same treatment for take-or-pay cost allocation as we did in SoCal's ACAP because the parties have raised the same arguments.

16. The take-or-pay costs should be put into rates subject to refund in the event PG&E is ultimately refunded some or all of them.

17. DRA's equitable sharing mechanism should be adopted because it provides PG&E with a reasonable opportunity to recover take-or-pay costs while striking a fair balance in allocating risks and costs between PG&E's ratepayers and shareholders.

18. We should adopt PG&E's forecast of $17.78/Bbl for crude oil because the difference between its and DRA's forecast is insignificant.

19. We should adopt PG&E's forecasts of alternate fuel prices.

20. We should adopt DRA's residential and commercial throughputs because we have not adopted PG&E's forecast of gas prices.

21. PG&E's estimate of industrial throughput of 1,512 MMth is more reasonable than DRA's or TURN's and therefore should be adopted.

22. We should adopt an interdepartmental use throughput forecast of 3 MMth because DRA and PG&E agree.

23. We should adopt a gas department throughput of 60 MMth because DRA and PG&E agree.

24. We should adopt a LUAF throughput of 169 MMth because DRA and PG&E agree.

25. We should adopt PG&E's estimate for steam heat of 10 MMth because it varies only slightly from DRA's.

26. We should adopt 602 MMth of cogeneration throughput because it is an undisputed number.

27. We should adopt 358 MMth of EOR throughput because it is an undisputed number.

28. We should adopt a wholesale throughput of 112 MMth because it is an undisputed number.

29. We should adopt an industrial GC-2 throughput of 231 MMth and a cogeneration GC-2 throughput 119 MMth because they are undisputed numbers.

30. We should adopt a UEG throughput of 1,309 MMth and a forecast of start-up fuel of 13 MMth because they are undisputed numbers.

31. PG&E's estimate of Cool Water throughput of 38 MMth is more reasonable than DRA's and should be adopted.

32. We should adopt an interutility throughput forecast of 120 MMcf/day or 460 MMth because it is between the conflicting evidence presented by the parties and ultimately it is a qualitative judgment call.

33. PG&E's discount adjustment calculation should not be adopted because it improperly excludes demand charges from its exit cost calculations.

34. We should adopt discount adjustment factors of 24.0% for G-IND class, 7.5% for G-P2B class, and 5.2% for G-COG class based on CACD's running of the DRA discount adjustment calculation using numbers adopted in this decision.

35. CACD should hold workshops on the discount adjustment methodologies as set forth in the ordering paragraphs below and should provide at least seven days' notice to all parties.

36. Most of the cost allocation factors have been agreed to by PG&E and DRA, as set forth in the Joint Comparison Exhibit and therefore should be adopted.

37. We should adopt PG&E's method for allocating state and federal income taxes because it employs the same method for cost allocation and rate design purposes.

38. It is reasonable to continue to allocate wholesale customers their portion of the Long-Term Contract Shortfall.

39. We should adopt a total revenue requirement of $2.871 billion based on the issues resolved in this decision.

40. We should adopt an interutility credit of $5.059 million.

41. We should adopt a shrinkage expense of $50.598 million based on the gas and throughput forecasts adopted today.

42. We should adopt a CPUC fee expense of $4.160 million based on our adopted throughput.

43. PG&E should update its balancing accounts as of January 31, 1990.

44. DRA's proposal for a $3 residential customer charge should be rejected.

45. We should adopt DRA's more moderate 20% reduction in the tier differential.

46. PG&E should not be required to show the LIRA surcharge as a separate item on its bill.

47. We should adopt a forecast of LIRA administrative expenses of $1.96 million because DRA and PG&E have reached agreement.

48. We should adopt PG&E's proposal to introduce two experimental schedules, G-NGV1 and G-NGV2, to be applicable to the sale of natural gas for use as a motor vehicle fuel.

49. We should not combine Rate Schedules G-P2B and G-IND because of differing load and cost characteristics between the two classes.

50. Cogeneration transportation rates should continue to be based on the recorded average UEG gas rate lagged by two months.

51. We should eliminate the Cogeneration Shortfall account and conduct an audit of the amounts prior to recovery in rates.

52. We should reject PG&E's FPC mechanism, CIG/CLFP's single volumetric rate proposal, FEA's cost allocation change for commercial and residential transportation rates, CPG's transport fee proposal, and TURN's AGR proposal at this time because the Commission has determined more appropriate forums for these and other issues since hearings were held in this ACAP.

53. Exhibit 57 should not be received in evidence due to foundation and relevancy objections.

54. CACD should hold workshops aimed at streamlining the 1990 ACAPs as set forth in the ordering paragraphs below.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company 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 7.

2. The revised tariff schedules shall be filed on or after the effective date of this decision and at least 3 days prior to their effective date.

3. The Commission Advisory and Compliance Division (CACD) is directed to convene workshops on the discount adjustment calculations and on streamlining the Annual Cost Allocation Proceeding (ACAP) process generally. All ACAP utilities shall and any interested parties may participate in these workshops. Notice of the workshops shall be sent to all ACAP utilities and to all parties to this proceeding at least 7 days before the workshop. CACD shall follow the schedule consistent with the discussion herein.

This order is effective today.

Dated April 11, 1990, at San Francisco, California.

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

I will file a written concurrence.

/s/ FREDERICK R. DUDA
Commissioner

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

DP

APPENDIX A
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List of Appearances

Applicant: Harry W. Long, Jr., Mark Huffman, and Roger Peters, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Michael Alcantar, Attorney at Law, for Cogenerators of Southern California; Chickering & Gregory, by C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Alvin S. Pak and Judy Anderson, Attorneys at Law, for San Diego Gas & Electric Company; Barkovich & Yap, by Barbara Barkovich, for California Large Energy Consumers Association; Tom Beach and Brady & Berliner, by Roger A. Berliner, Attorney at Law, for Alberta Petroleum Marketing Commission; Morrison & Foerster, by Jerry R. Bloom and Davis G. Reese, Attorneys at Law, for California Cogeneration Council; Matthew V. Brady, Attorney at Law, for State Department of General Services; Maurice Brubaker, for Drazen-Brubaker & Associates, Inc; Phillip Di Virgilio, for PSE; Karen Edson, for KKE & Associates; Michel Florio and Joel Singer, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Sam De Frawi, for the Department of the Navy; Norman J. Furuta, Attorney at Law, for Federal Executive Agencies; Adrian Hudson, for California Gas Producers Association; Frank J. Cooley, Attorney at Law, for Southern California Edison Company; John W. Jimison, Attorney at Law, for Canadian Producer Group; Paul Kaufman, Attorney at Law, for Texaco Producing, Inc.; Luce, Forward, Hamilton & Scripps, by John Leslie, Attorney at Law, for Salmon Resources Limited and Mock Resources, Inc.; Michael Manning, for SPURR; William B. Marcus, for JBS Energy, Inc.; Squire, Sanders & Dempsey, by Keith McCrea and Michael Mishkin, Attorneys at Law, for California Industrial Group and California League of Food Processors; Patrick McDonnell, for SunPacific Energy Management, Inc. and Sunrise Energy Company; O'Rourke & Company, by Thomas J. O'Rourke, for Southwest Gas Corporation; Skaff & Anderson, by Edward G. Poole, Attorney at Law, for Natural Gas Clearinghouse; Patrick J. Power, Attorney at Law, for City of Palo Alto; Paul Premo, for Chevron, U.S.A.; Thomas D. Clarke, Steven D. Patrick, and Roy M. Rawlings, Attorneys at Law, for Southern California Gas Company; Kathi Robertson and Wayne Meek, for Simpson Paper Company; Andrew Safir, for Recon Research Corporation; Donald W. Schoenbeck, for Regulatory and Cogeneration Services, Inc.; Downey, Brand, Seymour & Rohwer, by

APPENDIX A
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Philip A. Stohr, Attorney at Law, for Industrial Users; Nancy Thompson, for Barakat, Howard & Chamberlin; Robert K. Weatherwax, for Sierra Energy and Risk Assessments; Robert B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates; Harry K. Winters, for Regents, University of California; R. O. Baish, M. D. Ferguson, and R. L. Wu, Attorneys at Law, for El Paso Natural Gas Company; Messrs. Armour, St. John, Wilcox, Goodin & Schlotz, by James D. Squeri and Barbara Snider, Attorneys at Law, for Kelco Division of Merck & Company, Inc.; and Dian A. Grueneich, Attorney at Law, for herself.

Division of Ratepayer Advocates: Kathleen C. Maloney and John S. Wong, Attorneys at Law, Natalie Walsh, and Paul Fassinger.

Commission Advisory and Compliance Division: Scott Sanders and Sarita Sarvate.

(END OF APPENDIX A)

TABLE 1

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED GAS DEMAND & DELIVERIES

Forecast Period: April 1, 1990 to March 31, 1991

THROUGHPUT TYPE	GAS DEMAND (Mdth)
Residential	215,875.0
Commercial Core	84,288.0
Industrial (incl. GC-2)	151,224.0
Steam Heat	1,038.0
UEG-PG&E (incl. start-up)	132,201.0
UEG-Edison	3,823.0
Cogeneration (excl. GC-2)	48,309.0
Cogeneration (GC-2 only)	11,867.0
EOR Cogeneration	20,626.0
EOR Steaming	15,151.0
Company use	6,096.7
Unaccounted for	17,224.1
Wholesale	11,167.0
Interdepartmental	299.0
Interutility	45,990.0
TOTAL GAS DEMAND	765,178.8 Mdth

TABLE 2

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED DEMAND FORECAST by CUSTOMER CLASS

Forecast Period: April 1, 1990 to March 31, 1991

SCHEDULE AND CATEGORY		PRIORITY	DEMAND FORECAST (Mdth)
Residential			215,875.0
Commercial	G-NR1	P-1	68,677.5
Commercial	G-NR2C	P-1	5,335.4
Commercial	G-NR3N	P-1	17.1
Commercial	G-NR3T	P-1	42.0
Commercial	G-NR1	P-2A	2,124.0
Commercial	G-NR2C	P-2A	8,003.1
Commercial	G-NR3N	P-2A	25.7
Commercial	G-NR3T	P-2A	63.0
Total Commercial			84,288.0
Industrial	G-P2BC	P-2B	10,936.0
Industrial	G-P2BN	P-2B	3,029.0
Industrial	G-P2BT	P-2B	1,657.0
Industrial	G-INDC	P-3B	15,504.7
Industrial	G-INDN	P-3B	7,530.9
Industrial	G-INDT	P-3B	14,076.5
Industrial	GC-2C	P-3B	3,054.5
Industrial	GC-2N	P-3B	1,466.5
Industrial	GC-2T	P-3B	3,115.5
Industrial	G-INDC	P-4	31,479.3
Industrial	G-INDN	P-4	15,290.1
Industrial	G-INDT	P-4	28,579.5
Industrial	GC-2C	P-4	6,201.5
Industrial	GC-2N	P-4	2,977.5
Industrial	GC-2T	P-4	6,325.5
Total Industrial			151,224.0
Cogeneration	G-COGC	P-3A	24,152.4
Cogeneration	G-COGN	P-3A	9,404.8
Cogeneration	G-COGT	P-3A	14,751.6
Cogeneration	GC-2C	P-3A	5,933.6
Cogeneration	GC-2N	P-3A	2,325.5
Cogeneration	GC-2T	P-3A	3,608.2
Total Cogeneration			60,176.0
EOR Cogeneration	C	P-3A	0.0
EOR Cogeneration	N	P-3A	1,031.1
EOR Cogeneration	T	P-3A	19,594.9

TABLE 2 (cont'd)

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED DEMAND FORECAST by CUSTOMER CLASS

Forecast Period: April 1, 1990 to March 31, 1991

SCHEDULE AND CATEGORY		PRIORITY	DEMAND FORECAST (Mdth)
EOR Steaming	C	P-5	0.0
EOR Steaming	N	P-5	3,030.6
EOR Steaming	T	P-5	12,120.4
Total EOR			35,777.0
Steam Heat	G-NCT	P-4	1,038.0
UEG-PG&E		P-5	130,885.0
UEG-PG&E Start-up		P-2A	1,316.0
UEG-SCE	G-NCT	P-3B	3,058.4
UEG-SCE	G-NCT	P-5	764.6
Total UEG			136,024.0
Misc. company use		P-1	6,096.7
Unaccounted for		P-1	17,224.1
TOTAL RETAIL			707,722.8
Coalinga	G-WRT	P-1	156.2
CP National	G-WRT	P-1	75.0
Palo Alto	G-WRT	P-1	2,656.5
Southwest	G-WRT	P-1	6,104.3
Coalinga	G-WRT	P-2A	29.8
Palo Alto	G-WRT	P-2A	655.0
Southwest	G-WRT	P-2A	726.7
Palo Alto	G-WRT	P-3B	327.5
Southwest	G-WRT	P-3B	436.0
Total Wholesale			11,167.0
Interdepartmental	C	P-1	201.0
Interdepartmental	C	P-3B	98.0
Total Interdepartmental			299.0
Interutility		P-5	45,990.0
TOTAL			765,178.8

TABLE 3

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED DEMAND FORECAST by PRIORITY

Forecast Period: April 1, 1990 to March 31, 1991

PRIORITY	DEMAND FORECAST (Mdth)
P-1	322,460.9
P-2A	12,943.4
P-2B	15,622.0
P-3A	80,802.0
P-3B	48,668.6
P-4	91,891.3
P-5	192,790.6
TOTAL	765,178.8 Mdth

TABLE 4

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED SUPPLY FORECAST by PORTFOLIO CLASS

Forecast Period: April 1, 1990 to March 31, 1991

	PRIORITY	SUPPLY FORECAST (Mdth)	
CORE & CORE-ELECT PORTFOLIO			
Residential			215,875.0
Commercial G-NR1	P-1	68,677.5	
Commercial G-NR2C	P-1	5,335.4	
Commercial G-NR1	P-2A	2,124.0	
Commercial G-NR2C	P-2A	8,003.1	
Commercial			84,140.2
Industrial G-P2BC	P-2B	10,936.0	
Industrial G-INDC	P-3B	15,504.7	
Industrial GC-2C	P-3B	3,054.5	
Industrial G-INDC	P-4	31,479.3	
Industrial GC-2C	P-4	6,201.5	
Industrial			67,176.0
Cogeneration G-COGC	P-3A	24,152.4	
Cogeneration GC-2C	P-3A	5,933.6	
Cogeneration			30,086.0
EOR Cogeneration C	P-3A		0.0
EOR Steaming C	P-5		0.0
Interdepartmental C	P-1		201.0
UEG-PG&E Start-up	P-2A		1,316.0
UEG-PG&E	P-5		130,885.0
Steam Heat G-NCT	P-4		1,038.0
UEG-SCE G-NCT	P-3B	3,058.4	
UEG-SCE G-NCT	P-5	764.6	
UEG-SCE			3,823.0
Coalinga G-WRT	P-1	156.2	
CP National G-WRT	P-1	75.0	
Palo Alto G-WRT	P-1	2,656.5	
Southwest G-WRT	P-1	6,104.3	
Coalinga G-WRT	P-2A	29.8	
Palo Alto G-WRT	P-2A	655.0	
Southwest G-WRT	P-2A	726.7	
Palo Alto G-WRT	P-3B	327.5	
Southwest G-WRT	P-3B	436.0	

TABLE 4 (cont'd)

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED SUPPLY FORECAST by PORTFOLIO CLASS

Forecast Period: April 1, 1990 to March 31, 1991

	PRIORITY	SUPPLY FORECAST (Mdth)	
Wholesale			11,167.0
Interdepartmental C	P-3B		98.0
Subtotal			545,805.2
Company use			4,485.5
Unaccounted for			12,672.2
TOTAL CORE & CORE-ELECT PORTFOLIO			562,962.9
NON-CORE PORTFOLIO			
Commercial G-NR3N	P-1	17.1	
Commercial G-NR3N	P-2A	25.7	
Commercial			42.8
Industrial G-P2BN	P-2B	3,029.0	
Industrial G-INDN	P-3B	7,530.9	
Industrial GC-2N	P-3B	1,466.5	
Industrial G-INDN	P-4	15,290.1	
Industrial GC-2N	P-4	2,977.5	
Industrial			30,294.0
Cogeneration G-COGN	P-3A	9,404.8	
Cogeneration GC-2N	P-3A	2,325.5	
Cogeneration			11,730.3
EOR Cogeneration N	P-3A	1,031.1	
EOR Steaming N	P-5	3,030.6	
EOR			4,061.6
Interutility	P-5		25,546.6
Subtotal			71,675.3

TABLE 4 (cont'd)

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED SUPPLY FORECAST by PORTFOLIO CIASS

Forecast Period: April 1, 1990 to March 31, 1991

	PRIORITY	SUPPLY FORECAST (Mdth)	
Company use			589.0
Unaccounted for			1,664.1
TOTAL NON-CORE PORTFOLIO			73,928.5
TRANSPORTATION			
Commercial G-NR3T	P-1	42.0	
Commercial G-NR3T	P-2A	63.0	
Commercial			105.1
Industrial G-P2BT	P-2B	1,657.0	
Industrial G-INDT	P-3B	14,076.5	
Industrial GC-2T	P-3B	3,115.5	
Industrial G-INDT	P-4	28,579.5	
Industrial GC-2T	P-2A	6,325.5	
Industrial			53,754.0
Cogeneration G-COGT	P-3A	14,751.6	
Cogeneration GC-2T	P-3A	3,608.2	
Cogeneration			18,359.7
EOR Cogeneration T	P-3A	19,594.9	
EOR Steaming T	P-5	12,120.4	
EOR			31,715.4
Interutility	P-5		20,443.4
Subtotal			124,377.5
Company use			1,022.2
Unaccounted for			2,887.7
TRANSPORTATION			128,287.4
TOTAL SUPPLY FORECAST			765,178.8

TABLE 5

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED COSTS

Forecast Period: April 1, 1990 to March 31, 1991

	VOLUMES (Mdth)	PRICE ($/dth)	COSTS (000's of $)	
Core & Core-Elect Supplies				
California	92,323	2.0300	187,415.7	
Rocky Mountain	2,589	1.9500	5,048.6	
PGT-Canadian	300,090	2.0700	621,187.2	
El Paso	0	0.0000	0.0	
Southwest	163,042	2.3500	383,149.8	
Adj. Core/Core-elect pur	558,045			1,196,801.2
Core & Core-elect WACOG		2.1446		
Storage				
Storage Withdrawal	36,709	2.1446	78,727.3	
Storage Injection	(31,791)	2.1446	(68,180.0)	
Net storage	4,918			10,547.3
Non-Core Supplies				
Non-core purchases & WACOG	73,928	2.3600		174,471.2
Pipeline Demand Charges (fixed)				
PGT-Canadian			100,323.0	
PGT Cost of Service			35,052.0	
El Paso			42,403.0	177,778.0
Transition costs				
El Paso Direct bills:				
Liquids Settlements			6,837.0	
Take-or-Pay			64,800.0	
FERC Account 191			0.0	
Southland/Chevron			(48,078.0)	
Storage Related			0.0	
Subtotal				23,559.0

TABLE 5 (cont'd)

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED COSTS

Forecast Period: April 1, 1990 to March 31, 1991

	VOLUMES (Mdth)	PRICE ($/dth)	COSTS (000's of $)	
Balancing/Tracking accounts				
Core Purchased Gas Account (CPGA)				117,906.0
Other Core accounts:				
Core Fixed Cost Account (CFCA)			18,112.0	
Core Implementation Account (CIA)			8,176.0	
Conservation Cost Adjustment (CCA)			0.0	26,288.0
Non-Core accounts:				
Negotiated Revenue Stability Account (NRSA)			13,408.0	
Enhanced Oil Recovery Account (EORA)			(1,066.0)	
Noncore Implementation Account (NIA)			32,572.0	
A&S Interutility Balancing Account			(285.0)	
CFA Debt Service and Expenses			(6,883.0)	
Noncore Transition Cost Account (NTCA)			(4,715.0)	
Cogeneration Shortfall Account (CSA)			1,009.0	
Pilot Banking Reservation Fee (PBRFA)			0.0	
Noncore Brokerage Accrual (Sunsets)			0.0	
LIRA Account Balance			4,138.0	
Gas Gathering Revenue Balance			(1,115.0)	37,063.0
Company use and Unaccounted for				
Core Company Use	4,571	2.1696	9,917.5	
Core Unaccounted For	12,914	2.1696	28,018.1	
Total	17,485			37,935.5
Non-core Company Use	1,526	2.1696	3,310.2	
Non-core Unaccounted For	4,310	2.1696	9,351.8	
Total	5,836			12,662.0

TABLE 6

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED PROCUREMENT PRICES

Forecast Period: April 1, 1990 to March 31, 1991

	VOLUMES (Mdth)	COSTS (000's of $)	
Core Procurement			
Core purchases	308,394.2	661,392.3	
Net storage	2,717.9	5,828.8	
Core procurement demand	311,112.1		667,221.1
Less: Company use & unaccounted for	9,481.9		20,572.3
Add: Core Purchased Gas Account (CPGA)			84,452.0
Subtotal			731,100.8
Add: FF&U at 0.8986%			6,569.4
CORE SALES	301,630		737,670.2
CORE PROCUREMENT PRICE		$2.4456 /dth	
Core-elect Procurement			
Core-elect purchases	238,233.2	510,922.7	
Net storage	2,099.5	4,502.7	
Core-elect procurement demand	240,332.8		515,425.4
Less: Company use & unaccounted for	7,324.8		15,892.0
Add: Core Purchased Gas Account (CPGA)			31,924.0
Subtotal			531,457.4
Add: FF&U at 0.8986%			4,775.5
Subtotal			536,232.9
CORE-ELECT SALES	233,008.0	$2.3013	536,232.9
Adjusted Sales	218,561.3		
Brokerage Fees			8,270.0
BROKERAGE RATE		$0.0378	
CORE-ELECT PROCUREMENT PRICE		$2.3392 /dth	

TABLE 6 (cont'd)

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED PROCUREMENT PRICES

Forecast Period: April 1, 1990 to March 31, 1991

	VOLUMES (Mdth)	COSTS (000's of $)	
Non-Core Procurement			
Non-Core purchases	73,928.5		174,471.2
Less: Company use & unaccounted for	2,253.2		4,888.5
Subtotal			169,582.7
Add: FF&U at 0.8986%			1,523.8
Subtotal			171,106.5
NON-CORE SALES	71,675.3	$2.3872	171,106.5
Adjusted Sales	65,438.7		
Brokerage Fees			2,566.3
BROKERAGE RATE		$0.0392	
NON-CORE PROCUREMENT PRICE		$2.4265 /dth	
Wholesale Procurement			
Wholesale purchases	11,417.4	24,486.2	
Net storage	100.6	215.8	
Wholesale demand	11,518.1		24,702.0
Less: Company use & unaccounted for	351.0		761.6
Add: Core Purchased Gas Account			1,530.0
Subtotal			25,254.5
Add: FF&U at 0.8986%			226.9
Subtotal			25,481.5
WHOLESALE SALES	11,167.0	$2.2819	25,481.5
Adjusted Sales	11,167.0		
Brokerage Fees			396.0
BROKERAGE RATE		$0.0355	
WHOLESALE PROCUREMENT PRICE		$2.3173 /dth	

TABLE 7
PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED REVENUE REQUIREMENTS
Forecast Period: April 1, 1990 to March 31, 1991

		AMOUNTS (000's of $)
PROCUREMENT REVENUE REQUIREMENT		
Total Core Procur. Revenue (incl Core-elect)	1,273,903.1	
Total Non-core Procurement Revenue	171,106.5	
Total Wholesale Procurement Revenue	25,481.5	
Brokerage Fees (incl. FF&U)	11,224.0	
TOTAL PROCUREMENT REVENUE REQUIREMENT		1,456,233.6
TRANSMISSION REVENUE REQUIREMENT		
Auth. gas margin (As adopted in A.89-12-057)		
Common distribution	263,195.0	
Demand related transmission	192,593.0	
Demand related storage	49,085.0	
Customer related	471,403.0	
Commodity related	9,692.0	
50% Administrative & General	84,347.0	
Franchise & Uncollectibles	9,617.0	
Less: Brokerage Fees	(11,224.0)	
Less: Other operating revenue	(9,149.0)	
		1,059,559.0
Pipeline demand charges	177,778.0	
Add: FF&U at 0.8986%	1,597.4	
		179,375.4
Transition costs	23,559.0	
Add: FF&U at 0.8986%	211.7	
		23,770.7
EOR / Interutility Revenue Credit		(13,286.9)
DSM and RD&D Revenue Offset		(15,322.0)
Pipeline Demand Trueup	4,438.0	
Gas Storage Carrying Cost	14,095.0	
Gas Storage Trueup	(375.0)	
Other Core Balancing/tracking accounts	26,288.0	
Non-Core Balancing/tracking accounts	37,063.0	
Core Company use and unaccounted for gas	37,935.5	
Non-Core Company use and unaccounted for gas	12,662.0	
CFA Debt Service and Expense	2,205.0	
Gas Exploration and Dev. Acct. (GEDA)	26,394.0	
CPUC Fee	4,159.8	
Low Income Rate Assist. (LIRA) A&G expense	1,961.0	
Add: FF&U at 0.8986%	1,499.0	
		168,325.3
TOTAL TRANSPORTATION REVENUE REQUIREMENT		1,402,421.6
NET REVENUE REQUIREMENT		2,858,655.1

TABLE 1

PACIFIC GAS AND ELECTRIC COMPANY
COST ALLOCATION SUMMARY

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	CORE COST ($000)	NON-CORE & CORE-ELECT ($000)	WHOLESALE COST ($000)
TRANSPORTATION REVENUE REQUIREMENT				
Commodity Related Base	9,692	4,651	4,869	172
Transmission Base	192,593	99,327	90,024	3,243
Storage Base	49,085	30,350	17,779	956
Distribution Base	263,195	229,778	33,417	0
Customer Base	471,403	461,693	9,504	206
50% Administrative and General	84,347	40,817	42,734	796
Other Operating Revenue	(9,149)	(7,408)	(1,695)	(46)
SUBTOTAL - Base (Margin)	1,061,166	859,207	196,631	5,328
Enhanced Oil Recovery Revenue Credit (EOR)	(8,228)	(6,315)	(1,858)	(55)
Interutility Transportation Service	(5,059)	(2,609)	(2,365)	(85)
Brokerage Fee: Procurement A&G	(5,035)	0	(4,863)	(172)
Brokerage Fee: Noncore Marketing	(117)	0	(115)	(2)
Brokerage Fee: Core Marketing	(6,072)	(6,072)	0	0
TOTAL - Adjusted Base	1,036,655	844,211	187,432	5,013
Pipe Demand Charges	177,778	91,686	83,099	2,993
Pipeline Demand Trueup	4,438	0	4,284	154
Gas Storage Carrying Costs	14,095	8,715	5,105	275
Gas Storage Trueup	(375)	0	(356)	(19)
Storage Related Transition Costs	0	0	0	0
El Paso Liquids Settlement	6,837	3,281	3,435	122
FERC Acct. 191	0	0	0	0
El Paso Take-or-Pay	64,800	31,093	32,554	1,153
Southland/Chevron	(48,078)	(23,069)	(24,153)	(855)
CFA Debt Service and Expense	2,205	1,552	653	0
Gas Exploration & Development Acct	26,394	12,665	13,260	470
Gas Dept Use & LUAF	50,598	24,278	25,419	900
CPUC Fee	4,160	2,580	1,580	0
Low Income Rate Assist. (LIRA) A&G	1,961	1,382	579	0
Demand Side Management	(14,242)	(13,949)	(287)	(6)
RD&D	(1,080)	(668)	(391)	(21)
TOTAL - Forecast Period Costs	1,326,145	983,756	332,212	10,177
AMORTIZATION OF BALANCING ACCOUNTS				
Core Fixed Cost Account (CFCA)	18,112	18,112	0	0
Core Implementation Acct. (CIA)	8,176	8,176	0	0
Noncore Implementation Account (NIA)	32,572	0	32,572	0
Noncore Transition Cost Account (NTCA)	(4,715)	0	(4,715)	0
Negotiated Revenue Stability Account (NRSA)	13,408	0	13,408	0
Enhanced Oil Recovery Account (EOR)	(1,066)	(818)	(241)	(7)
Alberta & Southern Interutility Account	(285)	(147)	(133)	(5)
CFA Debt Service and Expenses	(6,883)	(4,844)	(2,039)	0
Pilot Banking Reservation Fee (PBRFA)	0	0	0	0
Noncore Brokerage Accrual (Sunsets)	0	0	0	0
Low Income Rate Assistance (LIRA)	4,138	2,916	1,222	0
Cogeneration Shortfall Account (CSA)	1,009	0	1,009	0
Gas Gathering Revenue Balance	(1,115)	(575)	(521)	(19)
SUBTOTAL - Forecast Accnt Balances	63,351	22,820	40,562	(31)
F&U for Base, Nonbase & Balancing Revenue	12,925	6,227	6,519	179
TOTAL - Transport Revenue Req.	1,402,422	1,012,803	379,293	10,325
ALLOCATION ADJUSTMENTS				
G-10 Allocated Employee Discount	1,117	904	207	6
GC-2 Contract Revenue				
GC-2 Shortfall	(23,055)	0	(23,055)	0
GC-2 Shortfall Allocated	23,055	11,062	11,582	410
LIRA Discount Benefits	(11,323)	(11,323)	0	0
LIRA Discount Expenses	11,323	7,980	3,344	0
TOTAL - Transport Cost	1,403,538	1,021,426	371,371	10,741

TABLE 2

PACIFIC GAS AND ELECTRIC COMPANY
RESIDENTIAL CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	UNADJSTD ALLOCATION FACTOR 1/	UNADJSTD COST ($000)	ADJSTD ALLOCATION FACTOR 1/	ADJSTD COST ($000)
TRANSPORTATION REVENUE REQUIREMENT					
Commodity Related Base	9,692	0.3266	3,165	0.3432	3,326
Transmission Base	192,593	0.3574	68,826	0.3740	72,025
Storage Base	49,085	0.4516	22,166	0.4671	22,927
Distribution Base	263,195	0.6569	172,899	0.6726	177,036
Customer Base	471,403	0.9002	424,334	0.9002	424,334
50% Administrative and General	84,347	0.3292	27,769	0.3461	29,190
Other Operating Revenue	(9,149)	0.6719	(6,147)	0.6810	(6,230)
SUBTOTAL - Base (Margin)	1,061,166		713,012		722,608
Enhanced Oil Recovery Revenue Credit (E	(8,228)	0.6268	(5,157)	0.6369	(5,240)
Interutility Transportation Service	(5,059)	0.3574	(1,808)	0.3740	(1,892)
Brokerage Fee: Procurement A&G	(5,035)	0.0000	0	0.0000	0
Brokerage Fee: Noncore Marketing	(117)	0.0000	0	0.0000	0
Brokerage Fee: Core Marketing	(6,072)	0.9191	(5,581)	0.9191	(5,581)
TOTAL - Adjusted Base	1,036,655		700,467		709,895
Pipe Demand Charges	177,778	0.3574	63,531	0.3740	66,484
Pipeline Demand Trueup	4,438	0.0000	0	0.0000	0
Gas Storage Carrying Costs	14,095	0.4516	6,365	0.4671	6,584
Gas Storage Trueup	(375)	0.0000	0	0.0000	0
Storage Related Transition Costs	0	0.4516	0	0.4671	0
El Paso Liquids Settlement	6,837	0.3266	2,233	0.3432	2,346
FERC Acct. 191	0	0.3266	0	0.3432	0
El Paso Take-or-Pay	64,800	0.3266	21,163	0.3432	22,236
Southland/Chevron	(48,078)	0.3266	(15,702)	0.3432	(16,498)
CFA Debt Service and Expense	2,205	0.4710	1,038	0.5033	1,110
Gas Exploration & Development Acct	26,394	0.3266	8,620	0.3432	9,057
Gas Dept Use & LUAF	50,598	0.3270	16,547	0.3432	17,363
CPUC Fee	4,160	0.4162	1,731	0.4435	1,845
Low Income Rate Assist. (LIRA) A&G	1,961	0.4939	969	0.4939	969
Demand Side Management	(14,242)	0.9002	(12,820)	0.9002	(12,820)
RD&D	(1,080)	0.4516	(488)	0.4671	(504)
TOTAL - Forecast Period Costs	1,326,145		793,655		808,065
AMORTIZATION OF BALANCING ACCOUNTS					
Core Fixed Cost Account (CFCA)	18,112	0.7152	12,953	0.7151	12,953
Core Implementation Acct. (CIA)	8,176	0.7152	5,847	0.7151	5,847
Noncore Implementation Account (NIA)	32,572	0.0000	0	0.0000	0
Noncore Transition Cost Account (NTCA)	(4,715)	0.0000	0	0.0000	0
Negotiated Revenue Stability Account (N	13,408	0.0000	0	0.0000	0
Enhanced Oil Recovery Account (EOR)	(1,066)	0.6268	(668)	0.6369	(679)
Alberta & Southern Interutility Account	(285)	0.3574	(102)	0.3740	(107)
CFA Debt Service and Expenses	(6,883)	0.4710	(3,242)	0.5033	(3,464)
Pilot Banking Reservation Fee (PBRFA)	0	0.0000	0	0.0000	0
Noncore Brokerage Accrual (Sunsets)	0	0.0000	0	0.0000	0
Low Income Rate Assistance (LIRA)	4,138	0.4939	2,044	0.4939	2,044
Cogeneration Shortfall Account (CSA)	1,009	0.0000	0	0.0000	0
Gas Gathering Revenue Balance	(1,115)	0.3574	(398)	0.3740	(417)
SUBTOTAL - Forecast Accnt Balances	63,351		16,434		16,177
F&U for Base, Nonbase & Balancing Reven	12,925		4,237		4,453
TOTAL - Transport Revenue Req.	1,402,422		814,326		828,696
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	1,117	0.6719	750	0.6810	760
GC-2 Contract Revenue					
GC-2 Shortfall	(23,055)				
GC-2 Shortfall Allocated	23,055	0.3266	7,529	0.3432	7,911
LIRA Discount Benefits	(11,323)	1.0000	(11,323)	1.0000	(11,323)
LIRA Discount Expenses	11,323	0.4939	5,593	0.4939	5,593
TOTAL - Transport Cost	1,403,538		816,875		831,637

1/ Unadjusted allocation factors are those without the inclusion of discount adjustment. Adjusted allocation factors are those adjusted for the discount adjustment.

TABLE 3

PACIFIC GAS AND ELECTRIC COMPANY
RESIDENTIAL CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

	SYSTEM	RESIDENTIAL
Core WACOG (Cents/Therm)	21.45	
Noncore WACOG (Cents/Therm)	23.60	
Uncollectibles Factor	0.00222	
Franchise Requirement Factor	0.00639	
CPUC Fee (Cents/Therm)	0.076	
Core & Core Elect Determinant	5453	2154
Noncore Determinant	420	0
Transportation Determinant	723	0
Unadjusted Average Year Determinant	6830	2230
Adjusted Average Year Determinant	6499	2230
Cold Year Annual Determinant	6868	2569
Cold Year Peak Season Determinant	3521	1644
C Year Noncoincident Peak MMTH Distrib	673	453
Weighted Average Number of Customers	3566508	3210400
LIRA Volumes (MM Therms)		149.19

ALLOCATION FACTORS	RESIDENTIAL UNADJUSTED	RESIDENTIAL ADJUSTED
Average Year Annual	0.32659	0.34315
Cold Year Annual	0.35736	0.37397
Cold Year Peak Season	0.45158	0.46710
C Year Noncoincident Peak MMTH Distrib	0.65692	0.67264
Weighted Average Number of Customers	0.90015	0.90015
Margin Excl. F&U/ Oth Op Rev	0.67191	0.68096
Fixed Cost	0.62678	0.63691
Core Annual	0.71516	0.71516
Core Customer Cost	0.91908	0.91908
LIRA Thru-Put	0.49390	0.49390

TABLE 4

PACIFIC GAS AND ELECTRIC COMPANY
SMALL COMMERCIAL CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	UNADJSTD ALLOCATION FACTOR 1/	UNADJSTD COST ($000)	ADJSTD ALLOCATION FACTOR 1/	ADJSTD COST ($000)
TRANSPORTATION REVENUE REQUIREMENT					
Commodity Related Base	9,692	0.1093	1,060	0.1149	1,113
Transmission Base	192,593	0.1138	21,920	0.1191	22,939
Storage Base	49,085	0.1227	6,025	0.1270	6,232
Distribution Base	263,195	0.1642	43,211	0.1681	44,245
Customer Base	471,403	0.0772	36,382	0.0772	36,382
50% Administrative and General	84,347	0.1102	9,296	0.1159	9,772
Other Operating Revenue	(9,149)	0.1101	(1,008)	0.1128	(1,032)
SUBTOTAL - Base (Margin)	1,061,166		116,885		119,651
Enhanced Oil Recovery Revenue Credit (E	(8,228)	0.1107	(911)	0.1137	(935)
Interutility Transportation Service	(5,059)	0.1138	(576)	0.1191	(603)
Brokerage Fee: Procurement A&G	(5,035)	0.0000	0	0.0000	0
Brokerage Fee: Noncore Marketing	(117)	0.0000	0	0.0000	0
Brokerage Fee: Core Marketing	(6,072)	0.0788	(478)	0.0788	(478)
TOTAL - Adjusted Base	1,036,655		114,920		117,635
Pipe Demand Charges	177,778	0.1138	20,234	0.1191	21,174
Pipeline Demand Trueup	4,438	0.0000	0	0.0000	0
Gas Storage Carrying Costs	14,095	0.1227	1,730	0.1270	1,789
Gas Storage Trueup	(375)	0.0000	0	0.0000	0
Storage Related Transition Costs	0	0.1227	0	0.1270	0
El Paso Liquids Settlement	6,837	0.1093	747	0.1149	785
FERC Acct. 191	0	0.1093	0	0.1149	0
El Paso Take-or-Pay	64,800	0.1093	7,084	0.1149	7,444
Southland/Chevron	(48,078)	0.1093	(5,256)	0.1149	(5,523)
CFA Debt Service and Expense	2,205	0.1577	348	0.1685	372
Gas Exploration & Development Acct	26,394	0.1093	2,886	0.1149	3,032
Gas Dept Use & LUAF	50,598	0.1093	5,528	0.1149	5,813
CPUC Fee	4,160	0.1393	580	0.1485	618
Low Income Rate Assist. (LIRA) A&G	1,961	0.1772	347	0.1772	347
Demand Side Management	(14,242)	0.0772	(1,099)	0.0772	(1,099)
RD&D	(1,080)	0.1227	(133)	0.1270	(137)
TOTAL - Forecast Period Costs	1,326,145		147,917		152,250
AMORTIZATION OF BALANCING ACCOUNTS					
Core Fixed Cost Account (CFCA)	18,112	0.2394	4,336	0.2394	4,336
Core Implementation Acct. (CIA)	8,176	0.2394	1,957	0.2394	1,957
Noncore Implementation Account (NIA)	32,572	0.0000	0	0.0000	0
Noncore Transition Cost Account (NTCA)	(4,715)	0.0000	0	0.0000	0
Negotiated Revenue Stability Account (N	13,408	0.0000	0	0.0000	0
Enhanced Oil Recovery Account (EOR)	(1,066)	0.1107	(118)	0.1137	(121)
Alberta & Southern Interutility Account	(285)	0.1138	(32)	0.1191	(34)
CFA Debt Service and Expenses	(6,883)	0.1577	(1,085)	0.1685	(1,160)
Pilot Banking Reservation Fee (PBRFA)	0	0.0000	0	0.0000	0
Noncore Brokerage Accrual (Sunsets)	0	0.0000	0	0.0000	0
Low Income Rate Assistance (LIRA)	4,138	0.1772	733	0.1772	733
Cogeneration Shortfall Account (CSA)	1,009	0.0000	0	0.0000	0
Gas Gathering Revenue Balance	(1,115)	0.1138	(127)	0.1191	(133)
SUBTOTAL - Forecast Accnt Balances	63,351		5,664		5,579
F&U for Base, Nonbase & Balancing Reven	12,925		1,418		1,491
TOTAL - Transport Revenue Req.	1,402,422		154,999		159,320
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	1,117	0.1101	123	0.1128	126
GC-2 Contract Revenue					
GC-2 Shortfall	(23,055)				
GC-2 Shortfall Allocated	23,055	0.1093	2,520	0.1149	2,649
LIRA Discount Benefits	(11,323)	0.0000	0	0.0000	0
LIRA Discount Expenses	11,323	0.1772	2,006	0.1772	2,006
TOTAL - Transport Cost	1,403,538		159,649		164,101

1/ Unadjusted allocation factors are those without the inclusion of discount adjustment. Adjusted allocation factors are those adjusted for the discount adjustment.

TABLE 5

PACIFIC GAS AND ELECTRIC COMPANY
SMALL COMMERCIAL CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

	SYSTEM	SMALL COMMERCIAL
Core WACOG (Cents/Therm)	21.45	
Noncore WACOG (Cents/Therm)	23.60	
Uncollectibles Factor	0.00222	
Franchise Requirement Factor	0.00639	
CPUC Fee (Cents/Therm)	0.076	
Core & Core Elect Determinant	5453	721
Noncore Determinant	420	0
Transportation Determinant	723	0
Unadjusted Average Year Determinant	6830	747
Adjusted Average Year Determinant	6499	747
Cold Year Annual Determinant	6868	818
Cold Year Peak Season Determinant	3521	447
C Year Noncoincident Peak MMTH Distrib	673	113
Weighted Average Number of Customers	3566508	275254
LIRA Volumes (MM Therms)		0.00

ALLOCATION FACTORS	SMALL COMMERCIAL UNADJUSTED	SMALL COMMERCIAL ADJUSTED
Average Year Annual	0.10933	0.11488
Cold Year Annual	0.11382	0.11911
Cold Year Peak Season	0.12274	0.12696
C Year Noncoincident Peak MMTH Distrib	0.16418	0.16811
Weighted Average Number of Customers	0.07718	0.07718
Margin Excl. F&U/ Oth Op Rev	0.11015	0.11275
Fixed Cost	0.11067	0.11367
Core Annual	0.23940	0.23942
Core Customer Cost	0.07880	0.07880
LIRA Thru-Put	0.17718	0.17718

TABLE 6

PACIFIC GAS AND ELECTRIC COMPANY
LARGE COMMERCIAL CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	UNADJSTD ALLOCATION FACTOR 1/	UNADJSTD COST ($000)	ADJSTD ALLOCATION FACTOR 1/	ADJSTD COST ($000)
TRANSPORTATION REVENUE REQUIREMENT					
Commodity Related Base	9,692	0.0207	201	0.0218	211
Transmission Base	192,593	0.0216	4,169	0.0227	4,363
Storage Base	49,085	0.0235	1,151	0.0243	1,191
Distribution Base	263,195	0.0315	8,298	0.0323	8,497
Customer Base	471,403	0.0021	977	0.0021	977
50% Administrative and General	84,347	0.0209	1,764	0.0220	1,855
Other Operating Revenue	(9,149)	0.0155	(142)	0.0160	(146)
SUBTOTAL - Base (Margin)	1,061,166		16,420		16,948
Enhanced Oil Recovery Revenue Credit (E	(8,228)	0.0164	(135)	0.0169	(139)
Interutility Transportation Service	(5,059)	0.0216	(110)	0.0227	(115)
Brokerage Fee: Procurement A&G	(5,035)	0.0000	0	0.0000	0
Brokerage Fee: Noncore Marketing	(117)	0.0000	0	0.0000	0
Brokerage Fee: Core Marketing	(6,072)	0.0021	(13)	0.0021	(13)
TOTAL - Adjusted Base	1,036,655		16,163		16,681
Pipe Demand Charges	177,778	0.0216	3,848	0.0227	4,027
Pipeline Demand Trueup	4,438	0.0000	0	0.0000	0
Gas Storage Carrying Costs	14,095	0.0235	331	0.0243	342
Gas Storage Trueup	(375)	0.0000	0	0.0000	0
Storage Related Transition Costs	0	0.0235	0	0.0243	0
El Paso Liquids Settlement	6,837	0.0207	142	0.0218	149
FERC Acct. 191	0	0.0207	0	0.0218	0
El Paso Take-or-Pay	64,800	0.0207	1,345	0.0218	1,413
Southland/Chevron	(48,078)	0.0207	(998)	0.0218	(1,048)
CFA Debt Service and Expense	2,205	0.0299	66	0.0320	71
Gas Exploration & Development Acct	26,394	0.0207	548	0.0218	575
Gas Dept Use & LUAF	50,598	0.0207	1,049	0.0218	1,103
CPUC Fee	4,160	0.0264	110	0.0282	117
Low Income Rate Assist. (LIRA) A&G	1,961	0.0336	66	0.0336	66
Demand Side Management	(14,242)	0.0021	(30)	0.0021	(30)
RD&D	(1,080)	0.0235	(25)	0.0243	(26)
TOTAL - Forecast Period Costs	1,326,145		22,615		23,441
AMORTIZATION OF BALANCING ACCOUNTS					
Core Fixed Cost Account (CFCA)	18,112	0.0454	823	0.0454	823
Core Implementation Acct. (CIA)	8,176	0.0454	371	0.0454	372
Noncore Implementation Account (NIA)	32,572	0.0000	0	0.0000	0
Noncore Transition Cost Account (NTCA)	(4,715)	0.0000	0	0.0000	0
Negotiated Revenue Stability Account (N	13,408	0.0000	0	0.0000	0
Enhanced Oil Recovery Account (EOR)	(1,066)	0.0164	(17)	0.0169	(18)
Alberta & Southern Interutility Account	(285)	0.0216	(6)	0.0227	(6)
CFA Debt Service and Expenses	(6,883)	0.0299	(206)	0.0320	(220)
Pilot Banking Reservation Fee (PBRFA)	0	0.0000	0	0.0000	0
Noncore Brokerage Accrual (Sunsets)	0	0.0000	0	0.0000	0
Low Income Rate Assistance (LIRA)	4,138	0.0336	139	0.0336	139
Cogeneration Shortfall Account (CSA)	1,009	0.0000	0	0.0000	0
Gas Gathering Revenue Balance	(1,115)	0.0216	(24)	0.0227	(25)
SUBTOTAL - Forecast Accnt Balances	63,351		1,080		1,064
F&U for Base, Nonbase & Balancing Reven	12,925		269		283
TOTAL - Transport Revenue Req.	1,402,422		23,964		24,787
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	1,117	0.0155	17	0.0160	18
GC-2 Contract Revenue					
GC-2 Shortfall	(23,055)				
GC-2 Shortfall Allocated	23,055	0.0207	478	0.0218	503
LIRA Discount Benefits	(11,323)	0.0000	0	0.0000	0
LIRA Discount Expenses	11,323	0.0336	381	0.0336	381
TOTAL - Transport Cost	1,403,538		24,840		25,689

1/ Unadjusted allocation factors are those without the inclusion of discount adjustment. Adjusted allocation factors are those adjusted for the discount adjustment.

TABLE 7

PACIFIC GAS AND ELECTRIC COMPANY
LARGE COMMERCIAL CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

	SYSTEM	LARGE COMMERCIAL
Core WACOG (Cents/Therm)	21.45	
Noncore WACOG (Cents/Therm)	23.60	
Uncollectibles Factor	0.00222	
Franchise Requirement Factor	0.00639	
CPUC Fee (Cents/Therm)	0.076	
Core & Core Elect Determinant	5453	135
Noncore Determinant	420	0
Transportation Determinant	723	1
Unadjusted Average Year Determinant	6830	142
Adjusted Average Year Determinant	6499	142
Cold Year Annual Determinant	6868	156
Cold Year Peak Season Determinant	3521	85
C Year Noncoincident Peak MMTH Distrib	673	22
Weighted Average Number of Customers	3566508	7392
LIRA Volumes (MM Therms)		0.00

ALLOCATION FACTORS	LARGE COMMERCIAL UNADJUSTED	LARGE COMMERCIAL ADJUSTED
Average Year Annual	0.02075	0.02180
Cold Year Annual	0.02165	0.02265
Cold Year Peak Season	0.02346	0.02426
C Year Noncoincident Peak MMTH Distrib	0.03153	0.03228
Weighted Average Number of Customers	0.00207	0.00207
Margin Excl. F&U/ Oth Op Rev	0.01547	0.01597
Fixed Cost	0.01636	0.01693
Core Annual	0.04544	0.04544
Core Customer Cost	0.00212	0.00212
LIRA Thru-Put	0.03363	0.03363

TABLE 8

PACIFIC GAS AND ELECTRIC COMPANY
P2B-LARGE CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	UNADJSTD ALLOCATION FACTOR 1/	UNADJSTD COST ($000)	ADJSTD ALLOCATION FACTOR 1/	ADJSTD COST ($000)
TRANSPORTATION REVENUE REQUIREMENT					
Commodity Related Base	9,692	0.0237	230	0.0230	223
Transmission Base	192,593	0.0225	4,329	0.0218	4,189
Storage Base	49,085	0.0187	918	0.0179	878
Distribution Base	263,195	0.0171	4,504	0.0162	4,264
Customer Base	471,403	0.0012	552	0.0012	552
50% Administrative and General	84,347	0.0239	2,014	0.0232	1,957
Other Operating Revenue	(9,149)	0.0117	(107)	0.0113	(103)
SUBTOTAL - Base (Margin)	1,061,166		12,438		11,960
Enhanced Oil Recovery Revenue Credit (E	(8,228)	0.0133	(109)	0.0128	(105)
Interutility Transportation Service	(5,059)	0.0225	(114)	0.0218	(110)
Brokerage Fee: Procurement A&G	(5,035)	0.0436	(219)	0.0442	(223)
Brokerage Fee: Noncore Marketing	(117)	0.0568	(7)	0.0568	(7)
Brokerage Fee: Core Marketing	(6,072)	0.0000	0	0.0000	0
TOTAL - Adjusted Base	1,036,655		11,989		11,515
Pipe Demand Charges	177,778	0.0225	3,996	0.0218	3,867
Pipeline Demand Trueup	4,438	0.0443	197	0.0449	199
Gas Storage Carrying Costs	14,095	0.0187	263	0.0179	252
Gas Storage Trueup	(375)	0.0465	(17)	0.0468	(18)
Storage Related Transition Costs	0	0.0187	0	0.0179	0
El Paso Liquids Settlement	6,837	0.0237	162	0.0230	157
FERC Acct. 191	0	0.0237	0	0.0230	0
El Paso Take-or-Pay	64,800	0.0237	1,535	0.0230	1,491
Southland/Chevron	(48,078)	0.0237	(1,139)	0.0230	(1,106)
CFA Debt Service and Expense	2,205	0.0342	75	0.0337	74
Gas Exploration & Development Acct	26,394	0.0237	625	0.0230	607
Gas Dept Use & LUAF	50,598	0.0237	1,197	0.0230	1,164
CPUC Fee	4,160	0.0302	126	0.0297	124
Low Income Rate Assist. (LIRA) A&G	1,961	0.0384	75	0.0384	75
Demand Side Management	(14,242)	0.0012	(17)	0.0012	(17)
RD&D	(1,080)	0.0187	(20)	0.0179	(19)
TOTAL - Forecast Period Costs	1,326,145		19,048		18,367
AMORTIZATION OF BALANCING ACCOUNTS					
Core Fixed Cost Account (CFCA)	18,112	0.0000	0	0.0000	0
Core Implementation Acct. (CIA)	8,176	0.0000	0	0.0000	0
Noncore Implementation Account (NIA)	32,572	0.0450	1,465	0.0458	1,492
Noncore Transition Cost Account (NTCA)	(4,715)	0.0450	(212)	0.0458	(216)
Negotiated Revenue Stability Account (N	13,408	0.0450	603	0.0458	614
Enhanced Oil Recovery Account (EOR)	(1,066)	0.0133	(14)	0.0128	(14)
Alberta & Southern Interutility Account	(285)	0.0225	(6)	0.0218	(6)
CFA Debt Service and Expenses	(6,883)	0.0342	(235)	0.0337	(232)
Pilot Banking Reservation Fee (PBRFA)	0	0.0411	0	0.0448	0
Noncore Brokerage Accrual (Sunsets)	0	0.0000	0	0.0000	0
Low Income Rate Assistance (LIRA)	4,138	0.0384	159	0.0384	159
Cogeneration Shortfall Account (CSA)	1,009	0.0000	0	0.0000	0
Gas Gathering Revenue Balance	(1,115)	0.0225	(25)	0.0218	(24)
SUBTOTAL - Forecast Accnt Balances	63,351		1,735		1,773
F&U for Base, Nonbase & Balancing Reven	12,925		307		299
TOTAL - Transport Revenue Req.	1,402,422		21,090		20,438
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	1,117	0.0117	13	0.0113	13
GC-2 Contract Revenue					
GC-2 Shortfall	(23,055)				
GC-2 Shortfall Allocated	23,055	0.0237	546	0.0230	530
LIRA Discount Benefits	(11,323)	0.0000	0	0.0000	0
LIRA Discount Expenses	11,323	0.0384	435	0.0384	435
TOTAL - Transport Cost	1,403,538		22,083		21,416

1/ Unadjusted allocation factors are those without the inclusion of discount adjustment. Adjusted allocation factors are those adjusted for the discount adjustment.

TABLE 9

PACIFIC GAS AND ELECTRIC COMPANY
P2B-LARGE CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

	SYSTEM	P2B LARGE
Core WACOG (Cents/Therm)	21.45	
Noncore WACOG (Cents/Therm)	23.60	
Uncollectibles Factor	0.00222	
Franchise Requirement Factor	0.00639	
CPUC fee (Cents/Therm)	0.076	
Core & Core Elect Determinant	5453	109
Noncore Determinant	420	30
Transportation Determinant	723	17
Unadjusted Average Year Determinant	6830	162
Adjusted Average Year Determinant	6499	150
Cold Year Annual Determinant	6868	149
Cold Year Peak Season Determinant	3521	63
C Year Noncoincident Peak MMTH Distrib	673	11
Weighted Average Number of Customers	3566508	4176
LIRA Volumes (MM Therms)		0.00

ALLOCATION FACTORS	P2B LARGE UNADJUSTED	P2B LARGE ADJUSTED
Average Year Annual	0.02368	0.02301
Cold Year Annual	0.02248	0.02175
Cold Year Peak Season	0.01869	0.01788
C Year Noncoincident Peak MMTH Distrib	0.01711	0.01620
Weighted Average Number of Customers	0.00117	0.00117
Margin Excl. F&U/ Oth Op Rev	0.01172	0.01127
Fixed Cost	0.01326	0.01277
Core Annual	0.00000	0.00000
Core Customer Cost	0.00000	0.00000
LIRA Thru-Put	0.03838	0.03838

TABLE 10

PACIFIC GAS AND ELECTRIC COMPANY
OTHER INDUSTRIAL CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	UNADJSTD ALLOCATION FACTOR 1/	UNADJSTD COST ($000)	ADJSTD ALLOCATION FACTOR 1/	ADJSTD COST ($000)
TRANSPORTATION REVENUE REQUIREMENT					
Commodity Related Base	9,692	0.1780	1,725	0.1421	1,378
Transmission Base	192,593	0.1633	31,453	0.1299	25,014
Storage Base	49,085	0.1205	5,916	0.0947	4,650
Distribution Base	263,195	0.0876	23,047	0.0681	17,934
Customer Base	471,403	0.0133	6,261	0.0133	6,261
50% Administrative and General	84,347	0.1794	15,135	0.1434	12,092
Other Operating Revenue	(9,149)	0.0780	(714)	0.0629	(576)
SUBTOTAL - Base (Margin)	1,061,166		82,823		66,752
Enhanced Oil Recovery Revenue Credit (E	(8,228)	0.0903	(743)	0.0725	(597)
Interutility Transportation Service	(5,059)	0.1633	(826)	0.1299	(657)
Brokerage Fee: Procurement A&G	(5,035)	0.3276	(1,650)	0.2733	(1,376)
Brokerage Fee: Noncore Marketing	(117)	0.6448	(75)	0.6448	(75)
Brokerage Fee: Core Marketing	(6,072)	0.0000	0	0.0000	0
TOTAL - Adjusted Base	1,036,655		79,529		64,047
Pipe Demand Charges	177,778	0.1633	29,033	0.1299	23,090
Pipeline Demand Trueup	4,438	0.3220	1,429	0.2682	1,190
Gas Storage Carrying Costs	14,095	0.1205	1,699	0.0947	1,335
Gas Storage Trueup	(375)	0.2996	(112)	0.2482	(93)
Storage Related Transition Costs	0	0.1205	0	0.0947	0
El Paso Liquids Settlement	6,837	0.1780	1,217	0.1421	972
FERC Acct. 191	0	0.1780	0	0.1421	0
El Paso Take-or-Pay	64,800	0.1780	11,535	0.1421	9,211
Southland/Chevron	(48,078)	0.1780	(8,558)	0.1421	(6,834)
CFA Debt Service and Expense	2,205	0.2567	566	0.2085	460
Gas Exploration & Development Acct	26,394	0.1780	4,698	0.1421	3,752
Gas Dept Use & LUAF	50,598	0.1779	9,001	0.1421	7,192
CPUC Fee	4,160	0.2269	944	0.1837	764
Low Income Rate Assist. (LIRA) A&G	1,961	0.2569	504	0.2569	504
Demand Side Management	(14,242)	0.0133	(189)	0.0133	(189)
RD&D	(1,080)	0.1205	(130)	0.0947	(102)
TOTAL - Forecast Period Costs	1,326,145		131,164		105,299
AMORTIZATION OF BALANCING ACCOUNTS					
Core Fixed Cost Account (CFCA)	18,112	0.0000	0	0.0000	0
Core Implementation Acct. (CIA)	8,176	0.0000	0	0.0000	0
Noncore Implementation Account (NIA)	32,572	0.3381	11,014	0.2829	9,216
Noncore Transition Cost Account (NTCA)	(4,715)	0.3381	(1,594)	0.2829	(1,334)
Negotiated Revenue Stability Account (N	13,408	0.3381	4,534	0.2829	3,794
Enhanced Oil Recovery Account (EOR)	(1,066)	0.0903	(96)	0.0725	(77)
Alberta & Southern Interutility Account	(285)	0.1633	(47)	0.1299	(37)
CFA Debt Service and Expenses	(6,883)	0.2567	(1,767)	0.2085	(1,435)
Pilot Banking Reservation Fee (PBRFA)	0	0.5737	0	0.5140	0
Noncore Brokerage Accrual (Sunsets)	0	0.0000	0	0.0000	0
Low Income Rate Assistance (LIRA)	4,138	0.2569	1,063	0.2569	1,063
Cogeneration Shortfall Account (CSA)	1,009	0.0000	0	0.0000	0
Gas Gathering Revenue Balance	(1,115)	0.1633	(182)	0.1299	(145)
SUBTOTAL - Forecast Accnt Balances	63,351		12,925		11,045
F&U for Base, Nonbase & Balancing Reven	12,925		2,310		1,845
TOTAL - Transport Revenue Req.	1,402,422		146,398		118,188
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	1,117	0.0780	87	0.0629	70
GC-2 Contract Revenue					
GC-2 Shortfall	(23,055)				
GC-2 Shortfall Allocated	23,055	0.1780	4,104	0.1421	3,277
LIRA Discount Benefits	(11,323)	0.0000	0	0.0000	0
LIRA Discount Expenses	11,323	0.2569	2,909	0.2569	2,909
TOTAL - Transport Cost	1,403,538		153,498		124,445

1/ Unadjusted allocation factors are those without the inclusion of discount adjustment. Adjusted allocation factors are those adjusted for the discount adjustment.

TABLE 11

PACIFIC GAS AND ELECTRIC COMPANY
OTHER INDUSTRIAL CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

	SYSTEM	OTHER INDUSTRIAL
Core WACOG (Cents/Therm)	21.45	
Noncore WACOG (Cents/Therm)	23.60	
Uncollectibles Factor	0.00222	
Franchise Requirement Factor	0.00639	
CPUC Fee (Cents/Therm)	0.076	
Core & Core Elect Determinant	5453	519
Noncore Determinant	420	228
Transportation Determinant	723	427
Unadjusted Average Year Determinant	6830	1216
Adjusted Average Year Determinant	6499	924
Cold Year Annual Determinant	6868	892
Cold Year Peak Season Determinant	3521	334
C Year Noncoincident Peak MMTH Distrib	673	46
Weighted Average Number of Customers	3566508	47369
LIRA Volumes (MM Therms)		0.00

ALLOCATION FACTORS	OTHER INDUSTRIAL UNADJUSTED	OTHER INDUSTRIAL ADJUSTED
Average Year Annual	0.17800	0.14215
Cold Year Annual	0.16331	0.12988
Cold Year Peak Season	0.12052	0.09473
C Year Noncoincident Peak MMTH Distrib	0.08757	0.06814
Weighted Average Number of Customers	0.01328	0.01328
Margin Excl. F&U/ Oth Op Rev	0.07805	0.06290
Fixed Cost	0.09028	0.07252
Core Annual	0.00000	0.00000
Core Customer Cost	0.00000	0.00000
LIRA Thru-Put	0.25690	0.25690

TABLE 12

PACIFIC GAS AND ELECTRIC COMPANY
INDUSTRIAL LONG TERM CONTRACT CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	UNADJSTD ALLOCATION FACTOR 1/	UNADJSTD COST ($000)	ADJSTD ALLOCATION FACTOR 1/	ADJSTD COST ($000)
TRANSPORTATION REVENUE REQUIREMENT					
Commodity Related Base	9,692	0.0351	340	0.0369	357
Transmission Base	192,593	0.0322	6,199	0.0337	6,487
Storage Base	49,085	0.0238	1,166	0.0246	1,206
Distribution Base	263,195	0.0173	4,542	0.0177	4,651
Customer Base	471,403	0.0003	142	0.0003	142
50% Administrative and General	84,347	0.0354	2,983	0.0372	3,136
Other Operating Revenue	(9,149)	0.0144	(131)	0.0149	(137)
SUBTOTAL - Base (Margin)	1,061,166		15,240		15,841
Enhanced Oil Recovery Revenue Credit (E	(8,228)	0.0169	(139)	0.0176	(145)
Interutility Transportation Service	(5,059)	0.0322	(163)	0.0337	(170)
Brokerage Fee: Procurement A&G	(5,035)	0.0646	(325)	0.0709	(357)
Brokerage Fee: Noncore Marketing	(117)	0.0146	(2)	0.0146	(2)
Brokerage Fee: Core Marketing	(6,072)	0.0000	0	0.0000	0
TOTAL - Adjusted Base	1,036,655		14,611		15,168
Pipe Demand Charges	177,778	0.0322	5,722	0.0337	5,988
Pipeline Demand Trueup	4,438	0.0635	282	0.0696	309
Gas Storage Carrying Costs	14,095	0.0238	335	0.0246	346
Gas Storage Trueup	(375)	0.0591	(22)	0.0644	(24)
Storage Related Transition Costs	0	0.0238	0	0.0246	0
El Paso Liquids Settlement	6,837	0.0351	240	0.0369	252
FERC Acct. 191	0	0.0351	0	0.0369	0
El Paso Take-or-Pay	64,800	0.0351	2,273	0.0369	2,389
Southland/Chevron	(48,078)	0.0351	(1,687)	0.0369	(1,772)
CFA Debt Service and Expense	2,205	0.0506	112	0.0541	119
Gas Exploration & Development Acct	26,394	0.0351	926	0.0369	973
Gas Dept Use & LUAF	50,598	0.0351	1,774	0.0369	1,865
CPUC Fee	4,160	0.0447	186	0.0476	198
Low Income Rate Assist. (LIRA) A&G	1,961	0.0000	0	0.0000	0
Demand Side Management	(14,242)	0.0003	(4)	0.0003	(4)
RD&D	(1,080)	0.0238	(26)	0.0246	(27)
TOTAL - Forecast Period Costs	1,326,145		24,721		25,779
AMORTIZATION OF BALANCING ACCOUNTS					
Core Fixed Cost Account (CFCA)	18,112	0.0000	0	0.0000	0
Core Implementation Acct. (CIA)	8,176	0.0000	0	0.0000	0
Noncore Implementation Account (NIA)	32,572	0.0666	2,171	0.0734	2,390
Noncore Transition Cost Account (NTCA)	(4,715)	0.0666	(314)	0.0734	(346)
Negotiated Revenue Stability Account (N	13,408	0.0666	894	0.0734	984
Enhanced Oil Recovery Account (EOR)	(1,066)	0.0169	(18)	0.0176	(19)
Alberta & Southern Interutility Account	(285)	0.0322	(9)	0.0337	(10)
CFA Debt Service and Expenses	(6,883)	0.0506	(348)	0.0541	(372)
Pilot Banking Reservation Fee (PBRFA)	0	0.1217	0	0.1434	0
Noncore Brokerage Accrual (Sunsets)	0	0.0000	0	0.0000	0
Low Income Rate Assistance (LIRA)	4,138	0.0000	0	0.0000	0
Cogeneration Shortfall Account (CSA)	1,009	0.0000	0	0.0000	0
Gas Gathering Revenue Balance	(1,115)	0.0322	(36)	0.0337	(38)
SUBTOTAL - Forecast Accnt Balances	63,351		2,339		2,590
F&U for Base, Nonbase & Balancing Reven	12,925		455		478
TOTAL - Transport Revenue Req.	1,402,422		27,515		28,847
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	1,117	0.0144	16	0.0149	17
GC-2 Contract Revenue					
GC-2 Shortfall	(23,055)		(15,852)		(15,852)
GC-2 Shortfall Allocated	23,055	0.0351	809	0.0369	850
LIRA Discount Benefits	(11,323)	0.0000	0	0.0000	0
LIRA Discount Expenses	11,323	0.0000	0	0.0000	0
TOTAL - Transport Cost	1,403,538		12,487		13,862

1/ Unadjusted allocation factors are those without the inclusion of discount adjustment. Adjusted allocation factors are those adjusted for the discount adjustment.

TABLE 13

PACIFIC GAS AND ELECTRIC COMPANY
INDUSTRIAL LONG TERM CONTRACT CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

	SYSTEM	INDUSTRIAL LT CONTRCT
Core WACOG (Cents/Therm)	21.45	
Noncore WACOG (Cents/Therm)	23.60	
Uncollectibles Factor	0.00222	
Franchise Requirement Factor	0.00639	
CPUC Fee (Cents/Therm)	0.076	
Core & Core Elect Determinant	5453	93
Noncore Determinant	420	44
Transportation Determinant	723	94
Unadjusted Average Year Determinant	6830	240
Adjusted Average Year Determinant	6499	240
Cold Year Annual Determinant	6868	231
Cold Year Peak Season Determinant	3521	86
C Year Noncoincident Peak MMTH Distrib	673	12
Weighted Average Number of Customers	3566508	1072
LIRA Volumes (MM Therms)		0.00

ALLOCATION FACTORS	INDUSTRIAL LT CONTRCT UNADJUSTED	INDUSTRIAL LT CONTRCT ADJUSTED
Average Year Annual	0.03508	0.03686
Cold Year Annual	0.03219	0.03368
Cold Year Peak Season	0.02375	0.02457
C Year Noncoincident Peak MMTH Distrib	0.01726	0.01767
Weighted Average Number of Customers	0.00030	0.00030
Margin Excl. F&U/ Oth Op Rev	0.01436	0.01493
Fixed Cost	0.01692	0.01762
Core Annual	0.00000	0.00000
Core Customer Cost	0.00000	0.00000
LIRA Thru-Put	0.00000	0.00000

TABLE 14

PACIFIC GAS AND ELECTRIC COMPANY
UEG-PG&E WINTER CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	UNADJSTD ALLOCATION FACTOR 1/	UNADJSTD COST ($000)	ADJSTD ALLOCATION FACTOR 1/	ADJSTD COST ($000)
TRANSPORTATION REVENUE REQUIREMENT					
Commodity Related Base	9,692	0.0807	782	0.0848	822
Transmission Base	192,593	0.0767	14,773	0.0803	15,459
Storage Base	49,085	0.1514	7,431	0.1566	7,687
Distribution Base	263,195	0.0000	0	0.0000	0
Customer Base	471,403	0.0011	496	0.0011	496
50% Administrative and General	84,347	0.0814	6,864	0.0855	7,216
Other Operating Revenue	(9,149)	0.0284	(259)	0.0296	(271)
SUBTOTAL - Base (Margin)	1,061,166		30,087		31,409
Enhanced Oil Recovery Revenue Credit (E	(8,228)	0.0353	(290)	0.0369	(303)
Interutility Transportation Service	(5,059)	0.0767	(388)	0.0803	(406)
Brokerage Fee: Procurement A&G	(5,035)	0.1486	(748)	0.1631	(821)
Brokerage Fee: Noncore Marketing	(117)	0.0510	(6)	0.0510	(6)
Brokerage Fee: Core Marketing	(6,072)	0.0000	0	0.0000	0
TOTAL - Adjusted Base	1,036,655		28,654		29,872
Pipe Demand Charges	177,778	0.0767	13,636	0.0803	14,270
Pipeline Demand Trueup	4,438	0.1512	671	0.1658	736
Gas Storage Carrying Costs	14,095	0.1514	2,134	0.1566	2,207
Gas Storage Trueup	(375)	0.3764	(141)	0.4103	(154)
Storage Related Transition Costs	0	0.1514	0	0.1566	0
El Paso Liquids Settlement	6,837	0.0807	552	0.0848	580
FERC Acct. 191	0	0.0807	0	0.0848	0
El Paso Take-or-Pay	64,800	0.0807	5,231	0.0848	5,497
Southland/Chevron	(48,078)	0.0807	(3,881)	0.0848	(4,078)
CFA Debt Service and Expense	2,205	0.0000	0	0.0000	0
Gas Exploration & Development Acct	26,394	0.0807	2,131	0.0848	2,239
Gas Dept Use & LUAF	50,598	0.0807	4,082	0.0848	4,292
CPUC Fee	4,160	0.0000	0	0.0000	0
Low Income Rate Assist. (LIRA) A&G	1,961	0.0000	0	0.0000	0
Demand Side Management	(14,242)	0.0011	(15)	0.0011	(15)
RD&D	(1,080)	0.1514	(164)	0.1566	(169)
TOTAL - Forecast Period Costs	1,326,145		52,891		55,277
AMORTIZATION OF BALANCING ACCOUNTS					
Core Fixed Cost Account (CFCA)	18,112	0.0000	0	0.0000	0
Core Implementation Acct. (CIA)	8,176	0.0000	0	0.0000	0
Noncore Implementation Account (NIA)	32,572	0.1534	4,995	0.1688	5,500
Noncore Transition Cost Account (NTCA)	(4,715)	0.1534	(723)	0.1688	(796)
Negotiated Revenue Stability Account (N	13,408	0.1534	2,056	0.1688	2,264
Enhanced Oil Recovery Account (EOR)	(1,066)	0.0353	(38)	0.0369	(39)
Alberta & Southern Interutility Account	(285)	0.0767	(22)	0.0803	(23)
CFA Debt Service and Expenses	(6,883)	0.0000	0	0.0000	0
Pilot Banking Reservation Fee (PBRFA)	0	0.0000	0	0.0000	0
Noncore Brokerage Accrual (Sunsets)	0	0.0000	0	0.0000	0
Low Income Rate Assistance (LIRA)	4,138	0.0000	0	0.0000	0
Cogeneration Shortfall Account (CSA)	1,009	0.2972	300	0.3014	304
Gas Gathering Revenue Balance	(1,115)	0.0767	(86)	0.0803	(90)
SUBTOTAL - Forecast Accnt Balances	63,351		6,483		7,120
F&U for Base, Nonbase & Balancing Reven	12,925		1,047		1,101
TOTAL - Transport Revenue Req.	1,402,422		60,421		63,498
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	1,117	0.0284	32	0.0296	33
GC-2 Contract Revenue					
GC-2 Shortfall	(23,055)				
GC-2 Shortfall Allocated	23,055	0.0807	1,861	0.0848	1,956
LIRA Discount Benefits	(11,323)	0.0000	0	0.0000	0
LIRA Discount Expenses	11,323	0.0000	0	0.0000	0
TOTAL - Transport Cost	1,403,538		62,314		65,486

1/ Unadjusted allocation factors are those without the inclusion of discount adjustment. Adjusted allocation factors are those adjusted for the discount adjustment.

TABLE 15

PACIFIC GAS AND ELECTRIC COMPANY
UEG-PG&E WINTER CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

	SYSTEM	UEG-PG&E WINTER
Core WACOG (Cents/Therm)	21.45	
Noncore WACOG (Cents/Therm)	23.60	
Uncollectibles Factor	0.00222	
Franchise Requirement Factor	0.00639	
CPUC Fee (Cents/Therm)	0.076	
Core & Core Elect Determinant	5453	533
Noncore Determinant	420	0
Transportation Determinant	723	0
Unadjusted Average Year Determinant	6830	551
Adjusted Average Year Determinant	6499	551
Cold Year Annual Determinant	6868	551
Cold Year Peak Season Determinant	3521	551
C Year Noncoincident Peak MMTH Distrib	673	0
Weighted Average Number of Customers	3566508	3750
LIRA Volumes (MM Therms)		0.00

ALLOCATION FACTORS	UEG-PG&E WINTER UNADJUSTED	UEG-PG&E WINTER ADJUSTED
Average Year Annual	0.08073	0.08483
Cold Year Annual	0.07670	0.08027
Cold Year Peak Season	0.15140	0.15660
C Year Noncoincident Peak MMTH Distrib	0.00000	0.00000
Weighted Average Number of Customers	0.00105	0.00105
Margin Excl. F&U/ Oth Op Rev	0.02835	0.02960
Fixed Cost	0.03529	0.03687
Core Annual	0.00000	0.00000
Core Customer Cost	0.00000	0.00000
LIRA Thru-Put	0.00000	0.00000

TABLE 16

PACIFIC GAS AND ELECTRIC COMPANY
UEG-PG&E SUMMER CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	UNADJSTD ALLOCATION FACTOR 1/	UNADJSTD COST ($000)	ADJSTD ALLOCATION FACTOR 1/	ADJSTD COST ($000)
TRANSPORTATION REVENUE REQUIREMENT					
Commodity Related Base	9,692	0.1177	1,141	0.1237	1,199
Transmission Base	192,593	0.1118	21,537	0.1170	22,538
Storage Base	49,085	0.0000	0	0.0000	0
Distribution Base	263,195	0.0000	0	0.0000	0
Customer Base	471,403	0.0015	694	0.0015	694
50% Administrative and General	84,347	0.1186	10,007	0.1247	10,520
Other Operating Revenue	(9,149)	0.0312	(285)	0.0327	(299)
SUBTOTAL - Base (Margin)	1,061,166		33,093		34,651
Enhanced Oil Recovery Revenue Credit (E	(8,228)	0.0428	(352)	0.0448	(368)
Interutility Transportation Service	(5,059)	0.1118	(566)	0.1170	(592)
Brokerage Fee: Procurement A&G	(5,035)	0.2166	(1,091)	0.2377	(1,197)
Brokerage Fee: Noncore Marketing	(117)	0.0715	(8)	0.0715	(8)
Brokerage Fee: Core Marketing	(6,072)	0.0000	0	0.0000	0
TOTAL - Adjusted Base	1,036,655		31,077		32,485
Pipe Demand Charges	177,778	0.1118	19,880	0.1170	20,804
Pipeline Demand Trueup	4,438	0.2205	979	0.2417	1,072
Gas Storage Carrying Costs	14,095	0.0000	0	0.0000	0
Gas Storage Trueup	(375)	0.0000	0	0.0000	0
Storage Related Transition Costs	0	0.0000	0	0.0000	0
El Paso Liquids Settlement	6,837	0.1177	805	0.1237	846
FERC Acct. 191	0	0.1177	0	0.1237	0
El Paso Take-or-Pay	64,800	0.1177	7,626	0.1237	8,014
Southland/Chevron	(48,078)	0.1177	(5,658)	0.1237	(5,946)
CFA Debt Service and Expense	2,205	0.0000	0	0.0000	0
Gas Exploration & Development Acct	26,394	0.1177	3,106	0.1237	3,264
Gas Dept Use & LUAF	50,598	0.1176	5,951	0.1237	6,257
CPUC Fee	4,160	0.0000	0	0.0000	0
Low Income Rate Assist. (LIRA) A&G	1,961	0.0000	0	0.0000	0
Demand Side Management	(14,242)	0.0015	(21)	0.0015	(21)
RD&D	(1,080)	0.0000	0	0.0000	0
TOTAL - Forecast Period Costs	1,326,145		63,744		66,776
AMORTIZATION OF BALANCING ACCOUNTS					
Core Fixed Cost Account (CFCA)	18,112	0.0000	0	0.0000	0
Core Implementation Acct. (CIA)	8,176	0.0000	0	0.0000	0
Noncore Implementation Account (NIA)	32,572	0.2236	7,282	0.2462	8,018
Noncore Transition Cost Account (NTCA)	(4,715)	0.2236	(1,054)	0.2462	(1,161)
Negotiated Revenue Stability Account (N	13,408	0.2236	2,998	0.2462	3,301
Enhanced Oil Recovery Account (EOR)	(1,066)	0.0428	(46)	0.0448	(48)
Alberta & Southern Interutility Account	(285)	0.1118	(32)	0.1170	(33)
CFA Debt Service and Expenses	(6,883)	0.0000	0	0.0000	0
Pilot Banking Reservation Fee (PBRFA)	0	0.0000	0	0.0000	0
Noncore Brokerage Accrual (Sunsets)	0	0.0000	0	0.0000	0
Low Income Rate Assistance (LIRA)	4,138	0.0000	0	0.0000	0
Cogeneration Shortfall Account (CSA)	1,009	0.4332	437	0.4394	443
Gas Gathering Revenue Balance	(1,115)	0.1118	(125)	0.1170	(130)
SUBTOTAL - Forecast Accnt Balances	63,351		9,461		10,390
F&U for Base, Nonbase & Balancing Reven	12,925		1,527		1,605
TOTAL - Transport Revenue Req.	1,402,422		74,732		78,770
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	1,117	0.0312	35	0.0327	36
GC-2 Contract Revenue					
GC-2 Shortfall	(23,055)				
GC-2 Shortfall Allocated	23,055	0.1177	2,713	0.1237	2,851
LIRA Discount Benefits	(11,323)	0.0000	0	0.0000	0
LIRA Discount Expenses	11,323	0.0000	0	0.0000	0
TOTAL - Transport Cost	1,403,538		77,480		81,658

1/ Unadjusted allocation factors are those without the inclusion of discount adjustment. Adjusted allocation factors are those adjusted for the discount adjustment.

TABLE 17

PACIFIC GAS AND ELECTRIC COMPANY
UEG-PG&E SUMMER CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

	SYSTEM	UEG-PG&E SUMMER
Core WACOG (Cents/Therm)	21.45	
Noncore WACOG (Cents/Therm)	23.60	
Uncollectibles Factor	0.00222	
Franchise Requirement Factor	0.00639	
CPUC Fee (Cents/Therm)	0.076	
Core & Core Elect Determinant	5453	776
Noncore Determinant	420	0
Transportation Determinant	723	0
Unadjusted Average Year Determinant	6830	804
Adjusted Average Year Determinant	6499	804
Cold Year Annual Determinant	6868	804
Cold Year Peak Season Determinant	3521	0
C Year Noncoincident Peak MMTH Distrib	673	0
Weighted Average Number of Customers	3566508	5250
LIRA Volumes (MM Therms)		0.00

ALLOCATION FACTORS	UEG-PG&E SUMMER UNADJUSTED	UEG-PG&E SUMMER ADJUSTED
Average Year Annual	0.11769	0.12367
Cold Year Annual	0.11183	0.11702
Cold Year Peak Season	0.00000	0.00000
C Year Noncoincident Peak MMTH Distrib	0.00000	0.00000
Weighted Average Number of Customers	0.00147	0.00147
Margin Excl. F&U/ Oth Op Rev	0.03119	0.03265
Fixed Cost	0.04276	0.04476
Core Annual	0.00000	0.00000
Core Customer Cost	0.00000	0.00000
LIRA Thru-Put	0.00000	0.00000

TABLE 18

PACIFIC GAS AND ELECTRIC COMPANY
COGEN CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	UNADJSTD ALLOCATION FACTOR 1/	UNADJSTD COST ($000)	ADJSTD ALLOCATION FACTOR 1/	ADJSTD COST ($000)
TRANSPORTATION REVENUE REQUIREMENT					
Commodity Related Base	9,692	0.0732	710	0.0730	707
Transmission Base	192,593	0.0679	13,077	0.0674	12,975
Storage Base	49,085	0.0554	2,720	0.0543	2,667
Distribution Base	263,195	0.0204	5,374	0.0198	5,217
Customer Base	471,403	0.0027	1,292	0.0027	1,292
50% Administrative and General	84,347	0.0738	6,227	0.0736	6,206
Other Operating Revenue	(9,149)	0.0275	(251)	0.0272	(248)
SUBTOTAL - Base (Margin)	1,061,166		29,148		28,817
Enhanced Oil Recovery Revenue Credit (E	(8,228)	0.0333	(274)	0.0329	(271)
Interutility Transportation Service	(5,059)	0.0679	(344)	0.0674	(341)
Brokerage Fee: Procurement A&G	(5,035)	0.1348	(679)	0.1403	(706)
Brokerage Fee: Noncore Marketing	(117)	0.1331	(16)	0.1331	(16)
Brokerage Fee: Core Marketing	(6,072)	0.0000	0	0.0000	0
TOTAL - Adjusted Base	1,036,655		27,837		27,483
Pipe Demand Charges	177,778	0.0679	12,071	0.0674	11,977
Pipeline Demand Trueup	4,438	0.1339	594	0.1391	617
Gas Storage Carrying Costs	14,095	0.0554	781	0.0543	766
Gas Storage Trueup	(375)	0.1378	(52)	0.1424	(53)
Storage Related Transition Costs	0	0.0554	0	0.0543	0
El Paso Liquids Settlement	6,837	0.0732	501	0.0730	499
FERC Acct. 191	0	0.0732	0	0.0730	0
El Paso Take-or-Pay	64,800	0.0732	4,746	0.0730	4,728
Southland/Chevron	(48,078)	0.0732	(3,521)	0.0730	(3,508)
CFA Debt Service and Expense	2,205	0.0000	0	0.0000	0
Gas Exploration & Development Acct	26,394	0.0732	1,933	0.0730	1,926
Gas Dept Use & LUAF	50,598	0.0732	3,703	0.0730	3,692
CPUC Fee	4,160	0.0933	388	0.0943	392
Low Income Rate Assist. (LIRA) A&G	1,961	0.0000	0	0.0000	0
Demand Side Management	(14,242)	0.0027	(39)	0.0027	(39)
RD&D	(1,080)	0.0554	(60)	0.0543	(59)
TOTAL - Forecast Period Costs	1,326,145		48,882		48,421
AMORTIZATION OF BALANCING ACCOUNTS					
Core Fixed Cost Account (CFCA)	18,112	0.0000	0	0.0000	0
Core Implementation Acct. (CIA)	8,176	0.0000	0	0.0000	0
Noncore Implementation Account (NIA)	32,572	0.1391	4,531	0.1452	4,731
Noncore Transition Cost Account (NTCA)	(4,715)	0.1391	(656)	0.1452	(685)
Negotiated Revenue Stability Account (N	13,408	0.1391	1,865	0.1452	1,947
Enhanced Oil Recovery Account (EOR)	(1,066)	0.0333	(35)	0.0329	(35)
Alberta & Southern Interutility Account	(285)	0.0679	(19)	0.0674	(19)
CFA Debt Service and Expenses	(6,883)	0.0000	0	0.0000	0
Pilot Banking Reservation Fee (PBRFA)	0	0.2116	0	0.2366	0
Noncore Brokerage Accrual (Sunsets)	0	0.0000	0	0.0000	0
Low Income Rate Assistance (LIRA)	4,138	0.0000	0	0.0000	0
Cogeneration Shortfall Account (CSA)	1,009	0.2696	272	0.2592	262
Gas Gathering Revenue Balance	(1,115)	0.0679	(76)	0.0674	(75)
SUBTOTAL - Forecast Accnt Balances	63,351		5,882		6,125
F&U for Base, Nonbase & Balancing Reven	12,925		950		947
TOTAL - Transport Revenue Req.	1,402,422		55,715		55,493
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	1,117	0.0275	31	0.0272	30
GC-2 Contract Revenue					
GC-2 Shortfall	(23,055)				
GC-2 Shortfall Allocated	23,055	0.0732	1,688	0.0730	1,682
LIRA Discount Benefits	(11,323)	0.0000	0	0.0000	0
LIRA Discount Expenses	11,323	0.0000	0	0.0000	0
TOTAL - Transport Cost	1,403,538		57,434		57,205

1/ Unadjusted allocation factors are those without the inclusion of discount adjustment. Adjusted allocation factors are those adjusted for the discount adjustment.

TABLE 19

PACIFIC GAS AND ELECTRIC COMPANY
COGEN CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

	SYSTEM	COGEN
Core WACOG (Cents/Therm)	21.45	
Noncore WACOG (Cents/Therm)	23.60	
Uncollectibles Factor	0.00222	
Franchise Requirement Factor	0.00639	
CPUC fee (Cents/Therm)	0.076	
Core & Core Elect Determinant	5453	242
Noncore Determinant	420	94
Transportation Determinant	723	148
Unadjusted Average Year Determinant	6830	500
Adjusted Average Year Determinant	6499	474
Cold Year Annual Determinant	6868	463
Cold Year Peak Season Determinant	3521	191
C Year Noncoincident Peak MMTH Distrib	673	13
Weighted Average Number of Customers	3566508	9775
LIRA Volumes (MM Therms)		0.00

ALLOCATION FACTORS	COGEN UNADJUSTED	COGEN ADJUSTED
Average Year Annual	0.07323	0.07296
Cold Year Annual	0.06790	0.06737
Cold Year Peak Season	0.05541	0.05434
C Year Noncoincident Peak MMTH Distrib	0.02042	0.01982
Weighted Average Number of Customers	0.00274	0.00274
Margin Excl. F&U/ Oth Op Rev	0.02747	0.02716
Fixed Cost	0.03327	0.03293
Core Annual	0.00000	0.00000
Core Customer Cost	0.00000	0.00000
LIRA Thru-Put	0.00000	0.00000

TABLE 20

PACIFIC GAS AND ELECTRIC COMPANY
COGEN LONG TERM CONTRACT CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	UNADJSTD ALLOCATION FACTOR 1/	UNADJSTD COST ($000)	ADJSTD ALLOCATION FACTOR 1/	ADJSTD COST ($000)
TRANSPORTATION REVENUE REQUIREMENT					
Commodity Related Base	9,692	0.0180	174	0.0189	183
Transmission Base	192,593	0.0167	3,212	0.0175	3,362
Storage Base	49,085	0.0136	668	0.0141	691
Distribution Base	263,195	0.0050	1,320	0.0051	1,352
Customer Base	471,403	0.0001	67	0.0001	67
50% Administrative and General	84,347	0.0181	1,530	0.0191	1,608
Other Operating Revenue	(9,149)	0.0065	(60)	0.0068	(62)
SUBTOTAL - Base (Margin)	1,061,166		6,913		7,201
Enhanced Oil Recovery Revenue Credit (E	(8,228)	0.0080	(66)	0.0083	(68)
Interutility Transportation Service	(5,059)	0.0167	(84)	0.0175	(88)
Brokerage Fee: Procurement A&G	(5,035)	0.0331	(167)	0.0363	(183)
Brokerage Fee: Noncore Marketing	(117)	0.0069	(1)	0.0069	(1)
Brokerage Fee: Core Marketing	(6,072)	0.0000	0	0.0000	0
TOTAL - Adjusted Base	1,036,655		6,595		6,861
Pipe Demand Charges	177,778	0.0167	2,965	0.0175	3,103
Pipeline Demand Trueup	4,438	0.0329	146	0.0360	160
Gas Storage Carrying Costs	14,095	0.0136	192	0.0141	198
Gas Storage Trueup	(375)	0.0338	(13)	0.0369	(14)
Storage Related Transition Costs	0	0.0136	0	0.0141	0
El Paso Liquids Settlement	6,837	0.0180	123	0.0189	129
FERC Acct. 191	0	0.0180	0	0.0189	0
El Paso Take-or-Pay	64,800	0.0180	1,166	0.0189	1,225
Southland/Chevron	(48,078)	0.0180	(865)	0.0189	(909)
CFA Debt Service and Expense	2,205	0.0000	0	0.0000	0
Gas Exploration & Development Acct	26,394	0.0180	475	0.0189	499
Gas Dept Use & LUAF	50,598	0.0180	910	0.0189	956
CPUC Fee	4,160	0.0229	95	0.0244	102
Low Income Rate Assist. (LIRA) A&G	1,961	0.0000	0	0.0000	0
Demand Side Management	(14,242)	0.0001	(2)	0.0001	(2)
RD&D	(1,080)	0.0136	(15)	0.0141	(15)
TOTAL - Forecast Period Costs	1,326,145		11,772		12,294
AMORTIZATION OF BALANCING ACCOUNTS					
Core Fixed Cost Account (CFCA)	18,112	0.0000	0	0.0000	0
Core Implementation Acct. (CIA)	8,176	0.0000	0	0.0000	0
Noncore Implementation Account (NIA)	32,572	0.0342	1,113	0.0376	1,226
Noncore Transition Cost Account (NTCA)	(4,715)	0.0342	(161)	0.0376	(177)
Negotiated Revenue Stability Account (N	13,408	0.0342	458	0.0376	505
Enhanced Oil Recovery Account (EOR)	(1,066)	0.0080	(8)	0.0083	(9)
Alberta & Southern Interutility Account	(285)	0.0167	(5)	0.0175	(5)
CFA Debt Service and Expenses	(6,883)	0.0000	0	0.0000	0
Pilot Banking Reservation Fee (PBRFA)	0	0.0520	0	0.0613	0
Noncore Brokerage Accrual (Sunsets)	0	0.0000	0	0.0000	0
Low Income Rate Assistance (LIRA)	4,138	0.0000	0	0.0000	0
Cogeneration Shortfall Account (CSA)	1,009	0.0000	0	0.0000	0
Gas Gathering Revenue Balance	(1,115)	0.0167	(19)	0.0175	(19)
SUBTOTAL - Forecast Accnt Balances	63,351		1,378		1,519
F&U for Base, Nonbase & Balancing Reven	12,925		233		245
TOTAL - Transport Revenue Req.	1,402,422		13,384		14,058
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	1,117	0.0065	7	0.0068	8
GC-2 Contract Revenue					
GC-2 Shortfall	(23,055)		(7,202)		(7,202)
GC-2 Shortfall Allocated	23,055	0.0180	415	0.0189	436
LIRA Discount Benefits	(11,323)	0.0000	0	0.0000	0
LIRA Discount Expenses	11,323	0.0000	0	0.0000	0
TOTAL - Transport Cost	1,403,538		6,604		7,299

1/ Unadjusted allocation factors are those without the inclusion of discount adjustment. Adjusted allocation factors are those adjusted for the discount adjustment.

TABLE 21

PACIFIC GAS AND ELECTRIC COMPANY
COGEN LONG TERM CONTRACT CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

	SYSTEM	COGEN LT CONTRACT
Core WACOG (Cents/Therm)	21.45	
Noncore WACOG (Cents/Therm)	23.60	
Uncollectibles Factor	0.00222	
Franchise Requirement Factor	0.00639	
CPUC Fee (Cents/Therm)	0.076	
Core & Core Elect Determinant	5453	59
Noncore Determinant	420	23
Transportation Determinant	723	36
Unadjusted Average Year Determinant	6830	123
Adjusted Average Year Determinant	6499	123
Cold Year Annual Determinant	6868	120
Cold Year Peak Season Determinant	3521	50
C Year Noncoincident Peak MMTH Distrib	673	3
Weighted Average Number of Customers	3566508	510
LIRA Volumes (MM Therms)		0.00

ALLOCATION FACTORS	COGEN LT CONTRACT UNADJUSTED	COGEN LT CONTRACT ADJUSTED
Average Year Annual	0.01799	0.01890
Cold Year Annual	0.01668	0.01746
Cold Year Peak Season	0.01363	0.01408
C Year Noncoincident Peak MMTH Distrib	0.00502	0.00514
Weighted Average Number of Customers	0.00014	0.00014
Margin Excl. F&U/ Oth Op Rev	0.00651	0.00679
Fixed Cost	0.00797	0.00832
Core Annual	0.00000	0.00000
Core Customer Cost	0.00000	0.00000
LIRA Thru-Put	0.00000	0.00000

TABLE 22

PACIFIC GAS AND ELECTRIC COMPANY
WHOLESALE CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

FORECAST PERIOD COSTS	SYSTEM COST ($000)	UNADJSTD ALLOCATION FACTOR 1/	UNADJSTD COST ($000)	ADJSTD ALLOCATION FACTOR 1/	ADJSTD COST ($000)
TRANSPORTATION REVENUE REQUIREMENT					
Commodity Related Base	9,692	0.0169	164	0.0178	172
Transmission Base	192,593	0.0161	3,099	0.0168	3,243
Storage Base	49,085	0.0188	925	0.0195	956
Distribution Base	263,195	0.0000	0	0.0000	0
Customer Base	471,403	0.0004	206	0.0004	206
50% Administrative and General	84,347	0.0090	758	0.0094	796
Other Operating Revenue	(9,149)	0.0048	(44)	0.0050	(46)
SUBTOTAL - Base (Margin)	1,061,166		5,107		5,328
Enhanced Oil Recovery Revenue Credit (E	(8,228)	0.0064	(53)	0.0067	(55)
Interutility Transportation Service	(5,059)	0.0161	(81)	0.0168	(85)
Brokerage Fee: Procurement A&G	(5,035)	0.0312	(157)	0.0342	(172)
Brokerage Fee: Noncore Marketing	(117)	0.0212	(2)	0.0212	(2)
Brokerage Fee: Core Marketing	(6,072)	0.0000	0	0.0000	0
TOTAL - Adjusted Base	1,036,655		4,813		5,013
Pipe Demand Charges	177,778	0.0161	2,860	0.0168	2,993
Pipeline Demand Trueup	4,438	0.0317	141	0.0348	154
Gas Storage Carrying Costs	14,095	0.0188	265	0.0195	275
Gas Storage Trueup	(375)	0.0468	(18)	0.0510	(19)
Storage Related Transition Costs	0	0.0188	0	0.0195	0
El Paso Liquids Settlement	6,837	0.0169	116	0.0178	122
FERC Acct. 191	0	0.0169	0	0.0178	0
El Paso Take-or-Pay	64,800	0.0169	1,097	0.0178	1,153
Southland/Chevron	(48,078)	0.0169	(814)	0.0178	(855)
CFA Debt Service and Expense	2,205	0.0000	0	0.0000	0
Gas Exploration & Development Acct	26,394	0.0169	447	0.0178	470
Gas Dept Use & LUAF	50,598	0.0169	856	0.0178	900
CPUC Fee	4,160	0.0000	0	0.0000	0
Low Income Rate Assist. (LIRA) A&G	1,961	0.0000	0	0.0000	0
Demand Side Management	(14,242)	0.0004	(6)	0.0004	(6)
RD&D	(1,080)	0.0188	(20)	0.0195	(21)
TOTAL - Forecast Period Costs	1,326,145		9,738		10,177
AMORTIZATION OF BALANCING ACCOUNTS					
Core Fixed Cost Account (CFCA)	18,112	0.0000	0	0.0000	0
Core Implementation Acct. (CIA)	8,176	0.0000	0	0.0000	0
Noncore Implementation Account (NIA)	32,572	0.0000	0	0.0000	0
Noncore Transition Cost Account (NTCA)	(4,715)	0.0000	0	0.0000	0
Negotiated Revenue Stability Account (N	13,408	0.0000	0	0.0000	0
Enhanced Oil Recovery Account (EOR)	(1,066)	0.0064	(7)	0.0067	(7)
Alberta & Southern Interutility Account	(285)	0.0161	(5)	0.0168	(5)
CFA Debt Service and Expenses	(6,883)	0.0000	0	0.0000	0
Pilot Banking Reservation Fee (PBRFA)	0	0.0000	0	0.0000	0
Noncore Brokerage Accrual (Sunsets)	0	0.0000	0	0.0000	0
Low Income Rate Assistance (LIRA)	4,138	0.0000	0	0.0000	0
Cogeneration Shortfall Account (CSA)	1,009	0.0000	0	0.0000	0
Gas Gathering Revenue Balance	(1,115)	0.0161	(18)	0.0168	(19)
SUBTOTAL - Forecast Accnt Balances	63,351		(29)		(31)
F&U for Base, Nonbase & Balancing Reven	12,925		170		179
TOTAL - Transport Revenue Req.	1,402,422		9,878		10,325
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	1,117	0.0048	5	0.0050	6
GC-2 Contract Revenue					
GC-2 Shortfall	(23,055)				
GC-2 Shortfall Allocated	23,055	0.0169	390	0.0178	410
LIRA Discount Benefits	(11,323)	0.0000	0	0.0000	0
LIRA Discount Expenses	11,323	0.0000	0	0.0000	0
TOTAL - Transport Cost	1,403,538		10,274		10,741

1/ Unadjusted allocation factors are those without the inclusion of discount adjustment. Adjusted allocation factors are those adjusted for the discount adjustment.

TABLE 23

PACIFIC GAS AND ELECTRIC COMPANY
WHOLESALE CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1990 to March 31, 1991

	WHOLESALE	WHOLESALE
Core WACOG (Cents/Therm)	21.45	
Noncore WACOG (Cents/Therm)	23.60	
Uncollectibles Factor	0.00000	
Franchise Requirement Factor	0.00639	
CPUC Fee (Cents/Therm)	0.076	
Core & Core Elect Determinant	5453	112
Noncore Determinant	420	0
Transportation Determinant	723	0
Unadjusted Average Year Determinant	6830	116
Adjusted Average Year Determinant	6499	116
Cold Year Annual Determinant	6868	116
Cold Year Peak Season Determinant	3521	69
C Year Noncoincident Peak MMTH Distrib	673	0
Weighted Average Number of Customers	3566508	1560
LIRA Volumes (MM Therms)		0.00

ALLOCATION FACTORS	WHOLESALE UNADJUSTED	WHOLESALE ADJUSTED
Average Year Annual	0.01693	0.01779
Cold Year Annual	0.01609	0.01684
Cold Year Peak Season	0.01884	0.01948
C Year Noncoincident Peak MMTH Distrib	0.00000	0.00000
Weighted Average Number of Customers	0.00046	0.00044
Margin Excl. F&U/ Oth Op Rev	0.00481	0.00502
Fixed Cost	0.00643	0.00672
Core Annual	0.00000	0.00000
Core Customer Cost	0.00000	0.00000
LIRA Thru-Put	0.00000	0.00000

TABLE 25

PACIFIC GAS AND ELECTRIC COMPANY
COST ALLOCATION SUMMARY

DISCOUNT ADJUSTMENT CALCULATION
G-IND

		WEIGHTING FACTORS	GAS COST
CORE ELECT PROCURE	0.23392	0.437	0.23883
NONCORE PROCURE	0.24265	0.563	

G-IND	NO. 2	NO.6	PROPANE	REFINERIES	TOTAL
ALT. FUEL PRICE	0.41200	0.27900	0.51700	0.33992	
PLUS: PREMIUM	0.02000	0.02000	0.02000	0.00000	
PLUS: EXIT COSTS	0.02178	0.02178	0.02178	0.00000	
LESS: COST OF GAS	0.23883	0.23883	0.23883	0.23883	
MAX TRANSPORT RATE	0.21495	0.08195	0.31995	0.10109	
DEFAULT RATE	0.13946	0.13946	0.13946	0.13946	
% DISCOUNT REQUIRED	0.00000	0.41237	0.00000	0.27514	
UNADJUSTED VOLUME	334	409	19	401	1,162.84
ADJUSTMENT	0	169	0	110	279
ADJUSTED VOLUME	334	241	19	291	884
DISCOUNT ADJUSTMENT FACTOR					24.0%

DISCOUNT ADJUSTMENT CALCULATION
G-P28

		WEIGHTING FACTORS	GAS COST
CORE ELECT PROCURE	0.23392	0.700	0.23654
NONCORE PROCURE	0.24265	0.300	

G-P28	NO. 2	NO.6	PROPANE	REFINERIES	TOTAL
ALT. FUEL PRICE	0.41200	0.27900	0.51700	0.33992	
PLUS: PREMIUM	0.02000	0.02000	0.02000	0.00000	
PLUS: EXIT COSTS	0.02805	0.02805	0.02805	0.00000	
LESS: COST OF GAS	0.23654	0.23654	0.23654	0.23654	
MAX TRANSPORT RATE	0.22351	0.09051	0.32851	0.10338	
DEFAULT RATE	0.14826	0.14826	0.14826	0.14826	
% DISCOUNT REQUIRED	0.00000	0.38947	0.00000	0.30267	
UNADJUSTED VOLUME	7.20	9.17	112.77	27.08	156.22
ADJUSTMENT	0	4	0	8	12
ADJUSTED VOLUME	7	6	113	19	144
DISCOUNT ADJUSTMENT FACTOR					7.5%

TABLE 25

PACIFIC GAS AND ELECTRIC COMPANY
COST ALLOCATION SUMMARY

DISCOUNT ADJUSTMENT CALCULATION
G-COG

		WEIGHTING FACTORS	GAS COST
CORE ELECT PROCURE	0.23392	0.500	0.23828
NONCORE PROCURE	0.24265	0.500	

G-COG	NO. 2	NO.6	PROPANE	TOTAL
ALT. FUEL PRICE	0.41200	0.27900	0.51700	
PLUS: PREMIUM	0.02000	0.02000	0.02000	
PLUS: EXIT COSTS	0.02805	0.02805	0.02805	
LESS: COST OF GAS	0.23828	0.23828	0.23828	
MAX TRANSPORT RATE	0.22177	0.08877	0.32677	
DEFAULT RATE	0.11508	0.11508	0.11508	
% DISCOUNT REQUIRED	0.00000	0.22867	0.00000	
UNADJUSTED VOLUME	370.75	109.57	2.77	483.09
ADJUSTMENT	0	25	0	25
ADJUSTED VOLUME	371	85	3	458
DISCOUNT ADJUSTMENT FACTOR				5.2%

TABLE 25

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED CORE RATES AND REVENUES

Forecast Period: April 1, 1990 to March 31, 1991

CORE CUSTOMER CLASS	NUMBER OF CUSTOMERS	ADJUSTED SALES FORECAST (Mth)	PRESENT RATES ($/th)	PRESENT REVENUES (M$)	ADOPTED RATES ($/th)	ADOPTED REVENUES (M$)	ADOPTED CHANGE (%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
RESIDENTIAL							
Customers	3224230						
Tier I (Baseline)		1,544,762	0.44826	692,455	0.49712	767,932	10.9%
Tier II		609,423	0.84849	517,089	0.81730	498,084	-3.7%
GS,GT Adj.						(8,718)	
TOTAL RESIDENTIAL		2,154,184	0.56149	1,209,544	0.58365	1,257,298	4.7%
LIRA							
Customers	243775					0	
Tier I (Baseline)		114,509	0.38102	43,630	0.42182	48,302	10.7%
Tier II		39,174	0.72122	28,253	0.69398	27,186	-3.8%
LIRA SALES		153,683	0.56149	71,883	0.49538	76,131	5.9%
SMALL COMMERCIAL SCHEDULE G-NR1							
Customer Charge	195966		$12.29	28,901	$11.37	26,746	
Summer Rate		342,435	0.46190	158,171	0.47358	162,171	2.5%
Winter Rate		378,741	0.62368	236,213	0.63934	242,143	2.5%
Total G-NR1		721,176	0.58694	423,285	0.59772	431,061	1.8%
LARGE COMMERCIAL SCHEDULE G-NR2							
Customer Charge	453		$140.51	764	$129.84	706	
Summer Rate		64,284	0.38858	24,979	0.42599	27,385	9.6%
Winter Rate		71,112	0.52457	37,303	0.57509	40,896	9.6%
Total G-NR2		135,396	0.46565	63,046	0.50951	68,986	9.4%
COMMRCL (TRNSPRT ONLY) SCHEDULE G-NR3							
Customer Charge	8		$140.51	13	$129.84	12	
Summer Rate		711	0.18141	129	0.18143	129	0.0%
Winter Rate		767	0.31740	243	0.33053	254	4.1%
Total G-NR3		1,478	0.26109	386	0.26722	395	2.3%
G-NGV1							
Customer Charge	N/A	N/A	N/A	N/A	$8.10	N/A	N/A
Volumetric Rate		N/A	N/A	N/A	0.45719	N/A	N/A
Total G-NGV1		N/A	N/A	N/A	0.48852	N/A	N/A
G-NGV2							
Customer Charge	N/A	N/A	N/A	N/A	$8.10	N/A	N/A
Volumetric Rate		N/A	N/A	N/A	0.45719	N/A	N/A
Total G-NGV2		N/A	N/A	N/A	0.48852	N/A	N/A
Tot Bundled Commercial		858,050	0.56724	486,718	0.58323	500,442	2.8%
TOTAL CORE		3,012,234	0.56312	1,696,262	0.58353	1,757,740	3.6%

TABLE 26

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED NONCORE RATES AND REVENUES

Forecast Period: April 1, 1990 to March 31, 1991

NONCORE CUSTOMER CLASS	ANNUAL FORECAST DELIVERIES (MTH)	HISTORICAL BILLING DETERMINANT (MTH/CUST)	PRESENT RATES ($/th)	PRESENT REVENUES (M$)	ADOPTED RATE ($/TH)	ADOPTED REVENUES (M$)	ADOPTED CHANGE ($/TH)	ADOPTED CHANGE (%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
PRIORITY P2B								
Customer Charge		173	$207.98	432	$195.46	406	-12.52	-6.0%
Demand Charge D1		146,325	0.08547	12,506	0.05610	8,209	-0.02937	-34.4%
Demand Charge D2								
Summer		117,245	0.01072	1,257	0.01522	1,785	0.00450	42.0%
Winter		74,112	0.01840	1,364	0.02621	1,942	0.00781	42.4%
Volumetric Charge	144,452		0.04379	6,326	0.06282	9,074	0.01903	43.4%
TOT/AVE P2B	144,452		0.15150	21,884	0.14826	21,416	-0.00324	-2.1%
INDUSTRIAL								
Customer Charge		720	$519.71	4,490	$532.74	4,603	13.03	2.5%
Demand Charge D1		1,135,093	0.08844	100,388	0.04356	49,449	-0.04488	-50.7%
Demand Charge D2								
Summer		981,723	0.00745	7,314	0.00753	7,388	0.00008	1.0%
Winter		572,889	0.01373	7,866	0.01585	9,080	0.00212	15.4%
Volumetric Charge	892,349		0.04109	36,667	0.06043	53,924	0.01934	47.1%
INDUST Net of GC-2	892,349		0.14926	156,724	0.13946	124,445	-0.00980	-6.6%
GC-2 Industrial	231,410			13,530		12,995		
TOTAL INDUSTRIAL	1,123,759		0.15150	170,254	0.12230	137,440	-0.02920	-19.3%
UTILITY ELECTRIC GEN.								
Customer Charge		1	$102,285	1,227	$96,136	1,154	(6,149)	-6.0%
Demand Charge				149,620		104,974		
Volumetric Charge						44,500		
Tier I	242,137		0.04579	11,087	0.06385	15,460	0.01806	39.4%
Tier II	1,066,713		0.01404	14,977	0.02722	29,041	0.01318	93.9%
TOT/AVE UEG	1,308,850		0.13517	176,912	0.11508	150,628	(26,283)	-14.9%
COGENERATION								
Cogen Net of GC-2	458,031		0.12613	57,771	0.11508	52,712	(5,059)	-8.8%
GC-2 Cogen	118,672			6,771		6,856		
TOT/AVE COGENERATION	576,704		0.11192	64,542	0.10329	59,568	(4,974)	-7.7%
NONCORE SUBTOTAL								
Net of GC-2	2,803,682		0.14741	413,291	0.12455	349,201	-0.02286	-15.5%
Including GC-2	3,153,765		0.13748	433,592	0.11702	369,052	-0.02046	-14.9%
WHOLESALE								
Demand Charges				9,289		9,317	28	0.3%
Volumetric Charge	111,670		0.01212	1,353	0.01275	1,424	0.00063	5.2%
TOT/AVE WHOLESALE	111,670		0.09530	10,642	0.09619	10,741	0.00088	0.9%
TOT NONCORE								
Net of GC-2	2,915,352		0.14541	423,934	0.12346	359,942	-0.02195	-15.1%
Including GC-2	3,265,435		0.13604	444,235	0.11631	379,793	-0.01973	-14.5%

A.89-08-024
D.90-04-021

FREDERICK R. DUDA, Commissioner, concurring.

The balance that has been struck in this decision by ALJ Kathleen Kiernan-Harrington and the Commission is one that I support wholeheartedly with the exception of one matter of some significance. The balance of this decision, however, takes as given the structure of the ACAP process, its costs, rewards, incentives, and penalties. The structure of the ACAP process and its future direction are the focus of most of my comments. But first I will address the issue of inter-utility transportation throughput.

While I am concerned about placing more risk on PG&E for inter-utility transportation volumes, in the recent SoCal ACAP we adopted a substantially higher throughput, which creates unequal incentives between the two respective utilities. While there was apparently a somewhat inadequate record on this issue, there are compelling policy reasons for increasing the incentive for inter-utility transportation of gas from PG&E to SoCal. SoCal is capacity constrained, has limited use of its storage program because of inadequate capacity, has invoked curtailments, and faces increasing air quality problems which compel us to encourage economic gas use over oil as much as possible for UEG loads. Not only do I find DRA's arguments on this general issue convincing, I believe that we have very adequate grounds to establish a higher inter-utility throughput volume. In light of the above policy considerations, I find it difficult to agree with the adopted reasoning in our decision today; while the decision explains the lack of persuasive evidence, it also sets forth a "lesson" from the SoCal ACAP, as a basis for determining inter-utility throughput, which is based on some mean value of the parties in opposition.[1] If we take as given the lack of a clear empirical basis for inter-utility throughput, then I believe we should be consistent with our throughput adopted in the SoCal ACAP, or at least explain why we allow such deviation.

With regard to the larger issue of the structure of our ACAP process I am concerned about its litigiousness, the resources it requires, the gaming of gas price and throughput forecasts, the risk we have imposed by adhering to an embedded cost price cap, the incentives embodied in the ACAP, and the lack of consistency between the policy principles of the ACAP and our policy basis for the gas industry in general as articulated in recent Commission decisions. While addressing these problems in more detail, I will provide comments on certain pending proceedings before us and how resolution of these proceedings may mitigate some of my concerns.

The product of workshops and the proceeding on gas marginal cost would seem to provide some coherency to what seems otherwise to be a relatively ad-hoc set of decisions that are made in the ACAPs. The set of decisions that are currently made in an ACAP seem unconnected, without a consistent theme or set of principles. Moreover, the use of embedded costs for pricing and cost allocation is very inconsistent with our policy direction articulated elsewhere to let competitive market forces work and to create workable competition in gas procurement and transportation for the noncore. I strongly encourage the parties to our gas proceedings and the Commission to move forward as soon

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1 "The lesson we conclude from SoCal ACAP decision is that it is appropriate to pick a number somewhere in between those recommended by the parties when it is such a qualitative judgement call." (D. 90-04-021, pg. 52)

as possible to adopt methods to define long-run marginal costs (LRMC). Like electric rate design and revenue allocation, LRMC would then be used as a guide rule for cost allocation and rate design. If this were done in general rate case proceedings, then an annual or biennial ACAP would seem to be substantially simplified.

Although our proceedings on gas capacity brokering are currently on hold pending resolution of the gas OIR on procurement, capacity brokering looks to play a significant role in defining who obtains what capacity at what prices. With a self selecting bidding cue, the need for regulatory review is limited to oversight of bidding administration. Establishment of priorities for transportation and its pricing through capacity brokering could supplant significant aspects of regulatory ratemaking and rate design. Capacity brokering, of course, raises the issue of pricing in a regulatory setting at above the cost of service. I expect the Commission to urge the use of capacity brokering as a keystone of our gas transportation pricing and allocation policy. [2]

While the Commission made the determination in 1987 that we would impose an embedded cost cap on utility pricing of noncore gas services,[3] I believe it is time to revisit this issue in all its dimensions. The related issue is the risk and reward we impose on LDCs by setting throughput gas targets at fixed prices, without the potential for pricing above the embedded cost of gas services. If we do indeed remove LDCs from

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2 Capacity brokering is also a condition of our support for interstate pipeline expansion proposals. D. 90-02-016.
3 Commission Decision 87-03-044.

the merchant function, as is proposed in the procurement OIR, then any regulatory problems related to gas commodity pricing above cost-of-service are substantially reduced if not eliminated. If we are going to a marginal cost and marginal value based system of pricing and regulatory incentives, we must abandon embedded cost caps and principles. The embedded cost cap is a constraint to the use of capacity brokering and to more flexible pricing for noncore services in general. To be consistent with our prior stated policies, I believe we should consider removal of the embedded cost cap for noncore gas services. An example of the problems that otherwise may result is the return of long-term contract shortfalls as noncore wholesale costs, which creates increasing costs for this group, reduces the competitiveness of utility wholesale service, and leaves no flexibility to offset this increasing cost. If noncore gas services were not bound by embedded cost and pricing flexibility was allowed, then LDCs could respond to the competitive market forces which we are directly encouraging.

My final point is that the Commission should attempt to create rational expectations for our LDCs so that they can make the important investment, pricing, and management decisions which form the center of their responsiblity. But given the current nature of the ACAP process and the lack of first principles which are used, many of the decisions finally reached in the ACAP are difficult to anticipate. Thus, it is difficult to develop rational expectations of our regulation, either in the short or long term. If rational expectations are not easily formed, what kind of incentives are we providing, except for parties to game the process with regard to gas throughput and price forecasts. The adopted decision today seems far from a process to create expectations of "likely revenues at cost based rates,"[4] which, however inconsistent, is the fundamental premise of the ACAP.

I offer these comments in hopes that the Commission and parties to our ACAP process can help rationalize gas cost allocation and pricing so that utilities and customers are more able to face the increasingly competitive energy marketplace.

/s/ FREDERICK R. DUDA
Frederick R. Duda, Commissioner

April 11, 1990
San Francisco, California

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4 Today's Decision 90-04-021, pg. 3.

A.89-08-024
D.90-04-021

FREDERICK R. DUDA, Commissioner, concurring.

The balance that has been struck in this decision by ALJ Kathleen Kiernan-Harrington and the Commission is one that I support wholeheartedly with the exception of one matter of some significance. The balance of this decision, however, takes as given the structure of the ACAP process, its costs, rewards, incentives, and penalties. The structure of the ACAP process and its future direction are the focus of most of my comments. But first I will address the issue of inter-utility transportation throughput.

While I am concerned about placing more risk on PG&E for inter-utility transportation volumes, in the recent SoCal ACAP we adopted a substantially higher throughput, which creates unequal incentives between the two respective utilities. While there was apparently a somewhat inadequate record on this issue, there are compelling policy reasons for increasing the incentive for inter-utility transportation of gas from PG&E to SoCal. SoCal is capacity constrained, has limited use of its storage program because of inadequate capacity, has invoked curtailments, and faces increasing air quality problems which compel us to encourage economic gas use over oil as much as possible for UEG loads. Not only do I find DRA's arguments on this general issue convincing, I believe that we have very adequate grounds to establish a higher inter-utility throughput volume. In light of the above policy considerations, I find it difficult to agree with the adopted reasoning in our decision today; while the decision explains the lack of persuasive evidence, it also sets forth a "lesson" from the SoCal ACAP, as a basis for determining inter-utility throughput, which is based on some mean value of the parties in opposition.[1] If we take as given the lack of a clear empirical basis for inter-utility throughput, then I believe we should be consistent with our throughput adopted in the SoCal ACAP, or at least explain why we allow such deviation.

With regard to the larger issue of the structure of our ACAP process I am concerned about its litigiousness, the resources it requires, the gaming of gas price and throughput forecasts, the risk we have imposed by adhering to an embedded cost price cap, the incentives embodied in the ACAP, and the lack of consistency between the policy principles of the ACAP and our policy basis for the gas industry in general as articulated in recent Commission decisions. While addressing these problems in more detail, I will provide comments on certain pending proceedings before us and how resolution of these proceedings may mitigate some of my concerns.

The product of workshops and the proceeding on gas marginal cost would seem to provide some coherency to what seems otherwise to be a relatively ad-hoc set of decisions that are made in the ACAPs. The set of decisions that are currently made in an ACAP seem unconnected, without a consistent theme or set of principles. Moreover, the use of embedded costs for pricing and cost allocation is very inconsistent with our policy direction articulated elsewhere to let competitive market forces work and to create workable competition in gas procurement and transportation for the noncore. I strongly encourage the parties to our gas proceedings and the Commission to move forward as soon

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1 "The lesson we conclude from SoCal ACAP decision is that it is appropriate to pick a number somewhere in between those recommended by the parties when it is such a qualitative judgement call." (D. 90-04-021, pg. 52)

as possible tó adopt methods to define long-run marginal costs (LRMC). Like electric rate design and revenue allocation, LRMC would then be used as a guide rule for cost allocation and rate design. If this were done in general rate case proceedings, then an annual or biennial ACAP would seem to be substantially simplified.

Although our proceedings on gas capacity brokering are currently on hold pending resolution of the gas OIR on procurement, capacity brokering looks to play a significant role in defining who obtains what capacity at what prices. With a self selecting bidding cue, the need for regulatory review is limited to oversight of bidding administration. Establishment of priorities for transportation and its pricing through capacity brokering could supplant significant aspects of regulatory ratemaking and rate design. Capacity brokering, of course, raises the issue of pricing in a regulatory setting at above the cost of service. I expect the Commission to urge the use of capacity brokering as a keystone of our gas transportation pricing and allocation policy. [2]

While the Commission made the determination in 1987 that we would impose an embedded cost cap on utility pricing of noncore gas services,[3] I believe it is time to revisit this issue in all its dimensions. The related issue is the risk and reward we impose on LDCs by setting throughput gas targets at fixed prices, without the potential for pricing above the embedded cost of gas services. If we do indeed remove LDCs from

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2 Capacity brokering is also a condition of our support for interstate pipeline expansion proposals. D. 90-02-016.
3 Commission Decision 87-03-044.

the merchant function, as is proposed in the procurement OIR, then any regulatory problems related to gas commodity pricing above cost-of-service are substantially reduced if not eliminated. If we are going to a marginal cost and marginal value based system of pricing and regulatory incentives, we must abandon embedded cost caps and principles. The embedded cost cap is a constraint to the use of capacity brokering and to more flexible pricing for noncore services in general. To be consistent with our prior stated policies, I believe we should consider removal of the embedded cost cap for noncore gas services. An example of the problems that otherwise may result is the return of long-term contract shortfalls as noncore wholesale costs, which creates increasing costs for this group, reduces the competitiveness of utility wholesale service, and leaves no flexibility to offset this increasing cost. If noncore gas services were not bound by embedded cost and pricing flexibility was allowed, then LDCs could respond to the competitive market forces which we are directly encouraging.

My final point is that the Commission should attempt to create rational expectations for our LDCs so that they can make the important investment, pricing, and management decisions which form the center of their responsiblity. But given the current nature of the ACAP process and the lack of first principles which are used, many of the decisions finally reached in the ACAP are difficult to anticipate. Thus, it is difficult to develop rational expectations of our regulation, either in the short or long term. If rational expectations are not easily formed, what kind of incentives are we providing, except for parties to game the process with regard to gas throughput and price forecasts. The adopted decision today seems far from a process to create expectations of "likely revenues at cost based rates,"[4] which, however inconsistent, is the fundamental premise of the ACAP.

I offer these comments in hopes that the Commission and parties to our ACAP process can help rationalize gas cost allocation and pricing so that utilities and customers are more able to face the increasingly competitive energy marketplace.

Frederick R. Duda

Frederick R. Duda, Commissioner

April 11, 1990
San Francisco, California

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4 Todays Decision 90-04-021, pg. 3.