Decision 90 01 015 JAN 9 1990

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of SOUTHERN CALIFORNIA GAS COMPANY (U 904-G) for authority to revise its rates effective October 1, 1989, in its Annual Cost Allocation Proceeding	Application 89-04-021 (Filed April 12, 1989)
In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902-G) for authority to revise its rates effective October 1, 1989, in its Annual Cost Allocation Proceeding	Application 89-05-006 (Filed May 4, 1989)

(See Appendix A for Appearances.)

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O P I N I O N

In this order we address the annual cost allocation proceeding (ACAP) applications of Southern California Gas Company (SoCal) filed April 12, 1989, and San Diego Gas and Electric Company (SDG&E) filed, May 4, 1989.

I. Summary

This decision requires SoCal to reduce rates in the aggregate by $43.6 million for the test period through September 30, 1990. SoCal's residential rates are decreased 0.5%, and commercial rates are increased 5.5%. Average SoCal noncore transportation rates, exclusive of forecast increases in the cost of gas, are decreased by 50%.

The decision concludes that an appropriate forecast weighted average price for Low Sulfur Waxy Residual Oil (LSWR) in the Singapore market for the ACAP test period is $16.25. Based upon this oil price forecast, and other factors, we adopt an average spot gas price for the ACAP period of $2.19. We forecast that SoCal system demand will exceed system capacity and that Utility Electric Generation (UEG) curtailment will be necessary during the ACAP test period. We also conclude that any fuel switching that may occur during the ACAP period will occur during the same periods of time that curtailments will be necessary, and are therefore not expected to have an impact on system throughput. We adopt a core weighted average cost of gas (WACOG) of $2.36/MMBtu and a noncore WACOG of $2.20/MMBtu.

In addition, we also adopt an equitable sharing approach, recommended by the Commission's Division of Ratepayer Advocates (DRA), for the allocation of the direct billed portion of interstate pipeline take-or-pay costs.

This decision also requires SDG&E to decrease rates by $46.8 million. SDG&E's residential rates are decreased 2.1%, and commercial rates 2.3%. Average SDG&E noncore transportation rates, exclusive of forecast increases in the cost of gas, are decreased by 30.5%.

II. Procedural Background

On May 1, 1988 the Commission established a new regulatory framework for California gas utilities under which the utilities are required to file annual ACAP applications. The purpose of these ACAP proceedings is to adjust gas utility rates to reflect annual changes in cost. Among the principle factors considered in these proceedings are: any changes in authorized revenue requirement not previously reflected in rates; the amortization of balances in authorized balancing and tracking accounts; forecast changes in the cost of gas supplies reflected in core customer rates; forecast throughput to customers; and changes necessary to fairly allocate costs among the various customer classes for the one year ACAP test period.

This is the first ACAP proceeding for both SoCal and SDG&E.

In Application (A.) 89-04-021, SoCal requested that the Commission reduce its revenue requirement by $23 million for the test period October 1, 1989 through September 30, 1989. The requested reduction is a result of several factors including an overcollection in balancing and tracking accounts, a forecast increase in the cost of gas, and a revised forecast of system throughput. SoCal's proposed rate design would increase residential rates by 2%, and commercial rates by 5%. Noncore transportation rates, exclusive of gas costs, would decrease by an average of 17%.

SoCal's application reflects the effects of new long-term contracts that SoCal negotiated with its two largest customers, SDG&E and Southern California Edison Company (SCE). These contracts require approval of the Commission in order to take effect. If approved by the Commission, they would fix the rates to be paid by SDG&E and Edison for the ACAP period and would thereby have a number of consequences for this proceeding. The proposed contracts have been considered in Case (C.) 89-05-016 and the assigned Administrative Law Judge (ALJ) in that proceeding has issued a proposed decision recommending that the contracts not be approved. As a result of this recommendation, the proposed decision in this proceeding has been based upon the assumption that the ALJ's recommendation will be adopted.

In A.89-05-006, SDG&E also requested an overall rate decrease, the amount of which was contingent upon the Commission's review of the new long-term contract between SDG&E and SoCal. Under the terms of the new contract, costs allocated by SoCal to SDG&E would be reduced from current levels. If the contract is approved, SDG&E requests that its rates be reduced by $43.3 million for the ACAP test period. If the new contract is not approved, SDG&E requests a smaller overall decrease of $26.1 million. SDG&E's requested reduction is a result of several factors in addition to the proposed contract with SoCal. These factors include an overcollection in balancing accounts, a forecast reduction in rates charged to SDG&E by SoCal, a revised forecast of system throughput, and a number of changes SDG&E proposes, in the event the SDG&E-SoCal contract is not approved, to the allocation of SoCal's fixed costs to SDG&E.

By ruling of the assigned ALJ, the SoCal and SDG&E applications were consolidated for hearing and decision.

In addition to the applicants, the following parties actively participated in this proceeding: the Commission's Division of Ratepayer Advocates (DRA), Toward Utility Rate

Normalization (TURN), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), the Southern California Utility Power Pool and the Imperial Irrigation District (SCUPP/IID), the City of Long Beach (Long Beach), the California Industrial Group and the California League of Food Processors (CIG/CLFP), the California Cogeneration Council (CCC), the Cogenerators of Southern California (CSC), Salmon Resources Ltd. and Mock Resources, Inc. (Salmon/Mock), the Kelco Division of Merk & Company (Kelco), and the Western Mobilehome Association (WMA). In addition to these parties, a brief was filed by the Department of General Services of the State of California (DGS).

Eighteen days of hearings were held from July 11 through August 4, 1989, and Phase I of this proceeding was submitted with the filing of reply briefs on September 15, 1989.

III. SoCal Issues

A. Gas Throughput

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 and thus have a direct effect on rates. 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.

SoCal and the DRA were the only parties to present complete gas throughput forecasts. SoCal forecasts total throughput of 1,051 MMdth based upon total demand of 1,081.6 MMdth and forecast curtailment of 30.4 MMdth. DRA forecasts total demand and throughput of 1,146 MMdth. DRA forecasts no curtailment.

DRA's throughput forecast is approximately 64 MMdth, or 6 percent higher than the company's.

1. Demand Models

The primary differences between the company and DRA demand forecasts are in their forecasts of the noncore commercial, noncore industrial, utility electric generation (UEG) and enhanced oil recovery (EOR) sectors. Both SoCal and DRA used a combination of econometric modeling and noneconometric approaches to develop their demand forecasts. Their estimates for the noncore commercial and noncore industrial classes were based upon econometric modeling. UEG and EOR forecasts were developed exogenous to their econometric models.

The SoCal and DRA econometric models are fundamentally different in design. DRA's model is a double-logarithmic model, linear in design. This type of model has been frequently used in the past in Commission proceedings, and is a form with which the Commission is familiar. SoCal's model is of an unusual nonlinear design. DRA was unaware of, and SoCal was unable to cite, any other utility that uses a nonlinear model to forecast gas demand. Because of its nonlinear design, SoCal's model is considerably more difficult than DRA's to understand and evaluate. In fact, DRA testified that they were unable to thoroughly evaluate SoCal's model within the time constraints of this proceeding. DRA cited several reasons for this including incomplete explanations from SoCal, and the need for special computer software to which the DRA did not have access.

It is clear that a considerable amount of time and effort went into the development of both the DRA and SoCal econometric demand forecasting models. It is far less clear, however, which provides more accurate forecasts of gas demand.

Both models produced acceptable results when run to "backcast" 1988 demand, although DRA's model produced results closer to actual recorded demand. DRA's model was in error by less than 1%, whereas SoCal's was in error by 2.04%.

The inability of the DRA to thoroughly evaluate SoCal's model within the schedule allowed for this proceeding, which appears to be primarily a result of its nonlinear structure, causes us considerable concern. In PG&E's recent ACAP decision, Decision (D.) 89-05-073, we expressed concern about the complexity of the demand forecasting models used. The record in this proceeding has done nothing to allay our concerns about the use of increasingly complex econometric demand forecasting models. The models used to forecast demand in Commission proceedings must be made accessible and understandable to all parties with reasonable sophistication in modeling techniques and an interest in evaluating them. This is a fundamental prerequisite to our adoption of any model or its output. So long as reasonable and reliable results can be produced, we favor the use of less complex models wherever possible.

Because of the inability of SoCal to adequately explain its model, and because of counterintuitive results cited by the DRA, we are reluctant to adopt the company's demand forecast. We are also reluctant to adopt SoCal's forecasts because the input data does not include 1988 data, and thus does not incorporate the effects of changing customer behavior under the new gas industry structure. As a result of these concerns, we will adopt DRA's demand forecasts for most customer classes. We will not, however, adopt DRA's demand forecast in its entirety. Testimony identified several problems with DRA's model, and as a result of these problems our adopted demand forecasts for the commercial and industrial noncore sectors are slightly lower that DRA's forecasts. These adjustments are discussed in the sections which follow.

In spite of our decision to base our demand forecast on DRA's basic model, we acknowledge that SoCal's approach may have theoretical advantages. We encourage SoCal and DRA to evaluate ways in which SoCal's approach might be simplified and made more easily understandable, and do not intend by this decision to rule out the use of nonlinear models in future proceedings.

2. Alternate Fuel and Spot Gas Price Forecasts

Forecast oil and spot gas prices are key inputs essential for the development of accurate gas demand and throughput forecasts. They are necessary to determine whether fuel switching will occur, and the extent to which it will occur during the ACAP test period. They are also necessary to develop reasonable estimates of demand within customer classes, and thus are of significant importance to cost allocation.

Alternate fuel and spot gas price forecasts were developed by SoCal and DRA, and critiqued by nearly every other party appearing in the proceeding. The following average alternate fuel and spot prices were forecast by DRA and SoCal for the ACAP period:

	DRA ($/MMBtu)	SoCal ($/MMBtu)
Low Sulfur Waxy Resid.	$3.56	$2.79
Los Angeles No. 2 Diesel	4.66	3.77
Low Sulfur No. 6	3.24	2.57
Propane	3.97	3.97
Spot Gas	2.19	2.36

The differences between the DRA and SoCal forecasts of Low Sulfur Waxy Residual Oil (LSWR), Los Angeles No. 2 diesel, No. 6 low sulfur fuel oil (LSFO), and spot gas prices are a result of different forecasting methodologies. They also reflect different assumptions concerning Organization of Petroleum Exporting Countries (OPEC) actions and the effect of gradually declining excess deliverability of gas, sometimes referred to as "the shrinking gas bubble." DRA did not independently forecast propane, but has accepted SoCal's forecast for purposes of this ACAP.

a. LSWR, No. 2, and No. 6 Alternate Fuels

The differences between the SoCal and DRA forecasts of LSWR, No. 2 diesel fuel, and No. 6 fuel oil are a result of the use of different methodologies for forecasting oil prices, and differences in the oil price forecasts which result from the use of these different methodolcgies.

DRA's alternate fuel price forecasts are based upon DRA's forecast price of LSWR in the Singapore market, and upon trends in the prices of No. 2 and No. 6 fuel oil. DRA forecast LSWR Singapore using several statistical methods that DRA has employed in prior Energy Cost Adjustment Clause (ECAC) proceedings before the Commission. Applying this approach, DRA forecast LSWR Singapore to average $18.76/Bbl and to vary between $18 and $21/Bbl. DRA developed alternate No. 2 and No. 6 fuel prices by using two models which trend alternate fuel price changes, and by correlating alternate fuel prices with the forecast LSWR price using the historical price relationship of each fuel to LSWR.

SoCal's alternate fuel price forecasts, including LSWR, are based primarily upon the company's forecast of the Refiners Acquisition Cost of Crude (RACC). SoCal forecast RACC prices to vary between $15.50 to $16/Bbl on the assumption that OPEC producers will continue to exceed their assigned quotas, and that as a result, RACC prices will not differ significantly from their 1986-1988 average. SoCal's RACC forecast is based upon the experience and judgement of SoCal's witness and is subjective in nature. It was not based upon or supported by any quantitative or statistical analysis. SoCal developed alternate fuel price forecasts in a manner similar to that used by the DRA. SoCal's forecasts were based upon the historic relationship of each different fuel to oil prices. The primary difference was that SoCal used RACC prices (and spot OPEC crude prices as a proxy for RACC prices) in the correlation, whereas DRA used LSWR prices.

To compare the oil price forecasts of DRA and SoCal it is easiest to compare DRA's forecast LSWR price with SoCal's forecast LSWR price. (SoCal's LSWR price was derived from its forecast RACC price.) SoCal forecasts LSWR to average $14.30/Bbl and to vary from $13.80 to $14.65/Bbl. This compares to DRA's forecast average of $18.76/Bbl and range of $18 to $21/Bbl.

A variety of oil price forecasts and published prices were introduced in evidence to corroborate or impeach the forecasts of SoCal and DRA. Included among this additional information were independent price forecasts of the U.S. Energy Information Administration (EIA) and Data Resources Inc. (DRI); futures market prices for West Texas Intermediate crude (WTI); and recent LSWR prices published in Platt's Oilgram.

DRI and EIA forecast RACC prices for the ACAP period in vicinity of $16.75 to $17.95/Bbl. Relative LSWR and RACC prices have varied substantially over time. RACC prices have generally exceeded LSWR prices, but LSWR has occasionally exceeded RACC. Over the last three years, however, SoCal calculates that RACC prices have exceeded LSWR by an average of $1.68/Bbl. Assuming this recent average historical differential, the DRI and EIA RACC forecasts can be roughly equated to LSWR price forecasts of between $15.07 and $16.27/Bbl.

DRA testified that futures market prices for WTI, a benchmark crude, for the ACAP period reflected a RACC equivalent price of $16.88/Bbl. This is roughly equivalent to an LSWR price of $15/Bbl.

Platt's published prices for LSWR were $18.95 on June 15, 1989, but dropped to $15.95 on July 11, 1989, and to $15.35 on July 24, 1989.

Forecasting alternate fuel prices is far more of an art than a science. Accordingly, we will base our adopted forecast on the weight of both the statistical analyses and informed expert judgement presented.

After several years of wild price fluctuations, oil prices have stabilized somewhat. Although the price forecasts introduced in this proceeding range fairly widely, the data upon which these forecasts have been based show signs of increasing price stability. This is due to a variety of factors including increased cooperation among OPEC members, the end of the Iran-Iraq war, and a gradual but steady increase in world domand. We are persuaded by DRA that current prices will firm as we move into the ACAP period, and find DRA's statistical approach to oil price forecasting preferable to SoCal's heavy reliance on informed judgement unsupported by statistical analyses. DRA's forecast is, however, considerably higher than other forecasts and current prices reported after DRA's forecast was prepared. It appears that DRA's forecast may have been influenced, to a greater degree than warranted, by significant price increases for LSWR experienced in the first half of 1989. Based upon the evidence offered in this proceeding, it appears that these price increases evidence a general firming of the market, but that the absolute price levels reached also reflect a market response to temporary supply and demand imbalances.

Based upon all of these considerations, we will adopt an average LSWR price of $16.25/Bbl. This equates to approximately $3.12/MMBtu.

We will also adopt No. 2 and No. 6 alternate fuel prices consistent with this adopted average LSWR price. Based upon historic relationships between LSWR and alternative fuels, we find $4.15/MMBtu a reasonable average price for Los Angeles No. 2 diesel fuel, and $2.86 a reasonable average price for No. 6 low sulfur fuel oil for the ACAP period.

b. <u>Spot Gas Price Forecast</u>

DRA forecasts spot gas prices at the California-Arizona border (commonly called the "border price") to average $2.19/MMBtu and to vary from $2.06/MMBtu to $2.35/MMBtu during the ACAP forecast period. DRA's forecast was developed through the use of three different models: one based upon the historical price relationship of LSWR to spot gas, and two based only upon past history of spot gas prices.

SoCal forecasts spot gas border prices to average \$2.36/MMBtu and to vary from \$2.03/MMBtu to \$2.59/MMBtu. SoCal's forecast is based primarily, but not entirely, upon the company's forecast RACC price and the historic relationship of RACC and spot gas prices. SoCal developed a spot gas price in this manner, and then made a judgmental adjustment to the resulting price to reflect what it believes will be the effect of the gradually disappearing national surplus of gas deliverability. On this basis SoCal adjusted its spot gas price upward by 20 to 35 cents/MMBtu. This adjustment results in a higher forecast price than DRA, and a steady increase in SoCal's forecast price of gas relative to oil during the forecast period.

DRA made no such adjustment to its spot gas price, and took the position that the gradually changing supply and demand balance does not warrant making any such adjustment.

We are persuaded by DRA and will adopt a spot gas border price of \$2.19/MMBtu. The relationship of oil prices to spot gas prices is a strong indicator of future spot gas prices, but clearly does not account for all of the changes that have been observed in spot gas prices in recent years. SoCal has illustrated this well in citing variations up and down from 55% to 82% in the spot gas to RACC price ratio over the period from 1985 through 1989. For this reason, we find DRA's methodology which includes two models based upon historic spot gas prices preferable to SoCal's approach. Although we have adopted a lower LSWR price than DRA used in forecasting the spot gas price, DRA's spot gas price of \$2.19/MMBtu appears reasonable in light of historic spot gas prices and will be adopted. We also agree with DRA that there is insufficient evidence to warrant any adjustment to this price forecast to reflect the gradually changing gas demand/supply balance, particularly since uncontroverted evidence indicates that excess deliverability will continue to exist throughout the ACAP period.

3. System Capacity

Among the most hotly contested issues in this proceeding was whether gas throughput will be constrained by limitations on system capacity. This is a critical issue because it has a direct effect on total forecast throughput, and on throughput to the various customer classes upon which costs are allocated.

SoCal contends that demand exceeds system capacity. SoCal forecasts demand of 1,081.5 MMdth, capacity of 1,051.2 MMdth, and curtailment of 30.4 MMdth. Edison, PG&E, SDG&E, and SCUPP/IID generally concur with SoCal.

TURN and DRA contend that theoretical capacity exceeds demand. DRA forecasts demand of 1,146 MMdth, and adequate capacity to meet this demand. TURN concurs. TURN and DRA thus forecast system capacity approximately 94.8 MMdth greater than SoCal's forecast capacity.

The debate concerning system capacity was focused on three principle issues: (1) the interutility transport capacity available to SoCal from PG&E over PG&E's Line 300, (2) the level of utilization of gas supply available on the El Paso system that should be forecast, and (3) the storage injection capability of SoCal and the effect of gas storage on SoCal's system capacity. Each of these issues is discussed in the sections which follow.

a. Interutility Transport Capacity

Estimates of the availability of interutility transportation service to SoCal from PG&E are extremely important to the resolution of throughput issues in this proceeding. All parties concede that SoCal has insufficient capacity to serve all of the demand that DRA and SoCal forecast using only its own facilities and interstate pipeline facilities directly connected to

SoCal's system. The only way SoCal can serve all of the demand forecast during the ACAP period is through interutility transportation service from PG&E, if that service is available when needed, and at a sufficient capacity level.

SoCal forecasts that it will have available, and will be able to utilize, 150 MMcf/d of PG&E interutility transportation service, expressed as an average daily amount over the 12-month ACAP period. This amount of interutility capacity would not be sufficient to meet the demand SoCal has forecast, and as a result, SoCal has forecast significant curtailment.

TURN contends that sufficient additional gas will be available to SoCal through interutility transportation to avoid any curtailments, even assuming DRA's higher demand forecast. SoCal's take-away capacity from the PG&E system is 1,070 MMcf/d, subject to gas availability and local pipeline pressure at any given time, and TURN points out that only 342 MMcf/d of average annual capacity is necessary in order to avoid curtailments. TURN contends that gas demand on the PG&E system during the ACAP period will be enough below PG&E's system capacity to provide these additional volumes to SoCal. TURN points out that SoCal's forecast of 150 MMcf/d was based upon 1987-88 data which the company concedes were dry years. The dry weather caused abnormally high UEG demand on the PG&E system and reduced the interutility transport capacity available. TURN contends that assuming average hydro conditions may be sufficient by itself to support TURN's conclusion that there will be no curtailment.

DRA concurs with TURN, and agrees with TURN's conclusion that additional capacity should be available to avoid any curtailments under average year conditions, even under DRA's higher demand forecast.

SoCal, PG&E, and Edison strenuously disagree with TURN and DRA. They contend that SoCal's forecast of 150 MMcf/d is consistent with the Commission's adopted forecast of 176 MMcf/d of

PG&E interutility service adopted in PG&E's recent ACAP, D.89-05-073. Since this decision was based upon average hydro conditions, they argue that it corroborates SoCal's 150 MMcf/d forecast, and refutes TURN's claim that assuming average weather conditions requires an upward adjustment in the forecast. They also claim that a lower forecast than was adopted in PG&E's ACAP is now warranted because since our decision in that case, Sacramento Municipal Utility District residents have voted to shut the Rancho Seco nuclear power plant down. This, they contend, will increase PG&E UEG requirements above what was assumed in the PG&E ACAP.

TURN counters that D.89-05-073 provides no support whatsoever for SoCal's position because the adopted interutility transport forecast was based upon the assumption that interutility transport would be constrained by demand on SoCal's system. Since we now know that demand on the SoCal system is forecast to be far higher than assumed in the PG&E ACAP, D.89-05-073 provides no support for SoCal.

This is a very complex issue argued largely on the basis of qualitative evidence, but requiring a quantitative resolution. Several important facts seem relatively clear, however. First, SoCal's estimate is based upon dry year data. Since it is our policy to forecast throughput in ACAPs on average year conditions, SoCal's estimate cannot be adopted without adjustment to reflect average hydro conditions. Second, it is clear that assuming average year conditions, considerably more interutility capacity should exist than SoCal has forecast. Third, the interutility forecast adopted in PG&E's recent ACAP, D.89-05-073, was based on average year hydro conditions, but also on the assumption that interutility sales to southern California would be demand constrained not capacity constrained. As a result, the probative value of the forecast adopted in D.89-05-073 is not particularly great.

Unfortunately, the amount of additional capacity that should be forecast as a result of assuming average hydro conditions has not been quantified with much precision, and is subject to considerable dispute. TURN estimates that assuming average hydro conditions should increase available interutility capacity by 275 MMcf/d. PG&E argues for a much lower values citing, among other things, the interutility transport capacity in 1984 and 1985. TURN counters that 1984 and 1985 data is of little current value because the Diablo Canyon nuclear power plant was not on line at that time, and Diablo significantly reduces PG&E UEG requirements and thereby increases available interutility capacity. Moreover, TURN contends that, even assuming the validity of the relevant data PG&E has provided, the adjustment should be approximately 150 MMcf/d.

Based upon our evaluation of the conflicting evidence presented on this issue, we conclude that an additional 162 MMcf/d should be available, over and above what SoCal has assumed, as a result of assuming average hydro conditions on the PG&E system. We expect, however, that this increase will be largely offset by the shutdown of Rancho Seco. We estimate that the shut down of Rancho Seco will increase PG&E's UEG requirements by approximately 123 MMcf/d. Taking these offsetting considerations into account, we will adopt an average available interutility capacity of 189 MMcf/d. This adopted average is 39 MMcf/d greater than SoCal's estimate, but well below the TURN and DRA estimates.

b. <u>Use of Gas Storage</u>

SoCal, PG&E, and Edison have also argued that regardless of what theoretical capacity is available over PG&E's line 300, most of this capacity will not be available during the periods of time that SoCal will have the greatest need for it. SoCal will have the greatest need for additional capacity during periods of peak winter demand when the weather is unusually cold. During these periods, they allege, it is likely to be unusually cold on the PG&E system as well. Coincident high demand during these winter periods will reduce the effective additional capacity available to SoCal to well below the theoretical capacity of Line 300. As a result, they argue that the availability of theoretical capacity in excess of SoCal's 150 MMcf/d forecast is an insufficient basis for rejecting SoCal's estimate.

While not conceding that any significant periods of coincident high demand should be assumed, TURN and DRA respond that the effect of coincident high demand can, and should be reduced through the effective use of storage. They argue that SoCal should inject gas available from PG&E during periods of low demand and withdraw it from storage when coincident high demand reduces available interutility capacity. They argue that it is not only advisable for SoCal to follow this course of action, but allege that any other practice may be imprudent. They further contend that sufficient storage capability exists on the SoCal system to use a majority of the theoretical Line 300 capacity and to avoid curtailments even if periods of coincident high demand do occur on both SoCal and PG&E systems. They cite SoCal documents in support of this argument which they allegedly indicate that SoCal has average storage injection capacity of at least 700 MMcf/d. Finally, TURN alleges that SoCal has failed to recognize the availability of customer-owned gas in storage, and that this gas will have the effect of increasing throughput and decreasing any need for curtailment.

SoCal states that it maximized daily storage injections in the spring of 1989 in order to reach the core protection level of 70 Bcf as early as possible so as to avoid interruptions to UEG customers in the summer and fall. As a result, SoCal filled all its storage fields to capacity by June 1, except Aliso Canyon, the company's largest field. SoCal forecasts that this field will be only 43% full at start of ACAP period. Although various figures, up to 700 MMcf/d, were introduced concerning SoCal's storage injection capacity, SoCal contends that its injection capability is only 300 to 350 MMcf/d when all fields except Aliso Canyon are full. This will be the case, according to SoCal, during the critical storage injection season.

SoCal further alleges that it has incorporated the operation of storage fields in its forecast of throughput and that its gas balance model operates to maximize the level of service to customers. SoCal also contends that any model of storage utilization must be developed by assuming that, on an annual basis, storage injections and withdrawals will have a zero net balance. As a result, SoCal claims that customer-owned storage does not add any incremental gas to SoCal's supply/demand balance.

We are persuaded that SoCal will not be able to take advantage of the full theoretically available excess capacity on Line 300 because SoCal and PG&E can sometimes be expected to have high system demand during the same periods of time. Although the effect on interutility capacity of coincident high demand on both systems was not quantified by SoCal, or any other party, it can be expected to reduce available capacity below the theoretical maximum.

We also agree with TURN and DRA that the effect of coincident high demand on both systems can be mitigated through the effective use of storage. The only difficulty with this position is accurately quantifying this effect. No party presented any quantification. SoCal claimed that the effect of maximum utilization of storage was accounted for in its estimate of average annual interutility transport capacity, but presented little more than argument on the point. We agree with SoCal's explanation of how storage should be factored into the company's throughput forecast. Any model should assume that, on an annual basis, storage injections and withdrawals will have a zero net balance, and should maximize the use of storage to mitigate curtailment. It is unclear, however, whether SoCal's gas balance model in fact operates to maximize the level of service through the use of storage capability. SoCal offered no convincing evidence that effective use of storage could not increase average interutility capacity above the 150 MMcf/d level SoCal has forecast from PG&E through interutility sales. SoCal also failed to demonstrate that storage injection limitations on its own system, rather than supply or deliverability constraints on the interconnection capability between SoCal and PG&E, limited its utilization of interutility capacity to the 150 MMcf/d the company forecast. As a result of the conflicting evidence and the incompleteness of SoCal's testimony on the issue, we will assume that the company will have available a maximum storage injection capability of at least 300 MMcf/d, and up to 700 MMcf/d, during critical portions of the storage injection season.

We also conclude that this assumed injection capability will be sufficient for SoCal to accept the average annual 189 MMcf/d of gas we have estimated will be available to the company from PG&E over Line 300.

c. Utilization of El Paso System

DRA contends that additional capacity can be obtained through increased utilization of capacity on the El Paso system. Daily operating records of El Paso for 1987 and 1988 indicate that the system had more than 14% of its capacity unused during this period. 14% of El Paso's total capacity to California of 2890 MMcf/d equals 405 MMcf/d. DRA argues that if this unused capacity were utilized, 405 MMcf/d of additional capacity could be delivered to California for use by SoCal.

TURN makes a slightly different argument. El Paso capacity has not been fully utilized since the institution of transportation for end-users due to scheduling and supply performance problems created by the new program. TURN argues that increased experience with the new open access system should allow slightly better utilization on the El Paso system increasing utilization from 96% to 97%. If this factor is applied to the

El Paso capacity connected to SoCal of 1750 MMcf/d, it would increase SoCal's usable capacity by approximately 17.5 MMcf/d and would reduce SoCal's estimated curtailment by an equivalent amount. TURN also contends that additional gas will be available over the El Paso system to serve SoCal both directly and through PG&E.

SoCal disputes the premise of DRA's and TURN's argument that utilization of the El Paso system will improve. SoCal argues that no improvement in El Paso utilization should be forecast, because transport volumes are likely to increase which should offset increased experience with the new regulatory program. But, SoCal has also alleged, however, that the long-term contracts the company has negotiated with SCE and SDG&E, currently before the Commission for approval in C.89-05-016, et. al., will permit increased utilization of El Paso.

Even if utilization improves, SoCal contends that it will not make any difference in the company's forecast curtailment. SoCal claims that it has already assumed that it will utilize 96% of the 1750 MMcf/d of El Paso capacity connected to SoCal, after adjustment for scheduled maintenance and reduced summertime take-away capacity and that as a result, a significant portion of the 14% DRA says should be available has already been accounted for. Moreover, the remaining portion that would theoretically be available must come to SoCal through the company's interconnection with PG&E. SoCal claims that this portion will not increase delivery capability because it will be subject to the intrastate system constraints over Line 300 discussed above.

We conclude that increased experience with the new gas industry structure should bring improvement in the utilization of the El Paso system. A majority of the increase DRA cites has, however, already been accounted for by SoCal and TURN in their utilization estimates of SoCal's interconnection capacity with El Paso. A portion of the assumed increase has not been accounted for and would be available to SoCal through PG&E, but this portion will not increase deliveries. This is because of intrastate capacity constraints over Line 300 discussed above. Increased utilization of capacity to 97% from SoCal's assumed 96% will, however, make additional gas available to SoCal through SoCal's interconnection with El Paso. We agree with TURN that a 97% utilization factor is reasonable to assume for the ACAP period. This results in an increase in SoCal's assumed usable capacity from its interconnection with El Paso of 17.5 MMcf/d.

d. Potential Economic Curtailment

Edison recommends that throughput be revised downward by 30 MMth to reflect the impact of what it has called "economic curtailment". Edison uses the term economic curtailment to describe circumstances which exist when available gas supplies are not purchased by a gas utility because they are considered too expensive, and as a result of this decision, low priority customers are curtailed. Edison contends that this adjustment should be made because economic curtailment has occurred in the past, and Edison believes that the conditions which led to such curtailments are likely to exist during the ACAP period.

We are not persuaded. The possibility of conditions occurring during the ACAP period under which SoCal would have an incentive for what has been described as economic curtailment has not been sufficiently demonstrated to warrant incorporation into the adopted throughput forecast.

4. Discount Adjustment

The Commission has authorized gas utilities to discount rates in order to increase the sales volume over which the utilities' fixed costs are spread. The 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 adjustment is expressed as a percentage reduction in forecast industrial noncore demand. It is set at the appropriate percentage so that forecast sales (including sales achieved through discounting) multiplied by the ceiling rate equals total forecast revenue.

DRA has estimated that incremental revenue of $3,478,000 can be obtained through discounting. SoCal has estimated incremental revenue from discounting of $2,600,000. The difference is due to several factors: (1) different methods of calculation, (2) different price elasticities used to calculate the response to various discount levels, and (3) different assumed volumes of gas forecasted to be sold at undiscounted cost of service rates.

There are a number of differences between the methodologies used by SoCal and DRA to calculate the discount adjustment. Both parties appear to use variations on the discount adjustment methodology proposed by TURN in PG&E's recent ACAP, A.88-09-032, and they produce similar results. The significant difference is related to an adjustment which SoCal has applied to the results of the company's calculation. The company has proposed what it has referred to as a "practical adjustment". The justification for this adjustment, according to SoCal, is that to obtain maximum revenues through discounting rates, it must have perfect knowledge of its customers' willingness to pay, i.e., "it must know which customers require a discount and which customers do not, and it must know exactly how much of a discount is required for each customer." SoCal argues that it is unrealistic to expect the company to have perfect knowledge, and that as a result, some adjustment to the calculation of the revenue that can be achieved through discounting should be adopted.

Both TURN and DRA object to SoCal's proposed "practical" adjustment. They allege that the discount adjustment can never be so precise as to justify the kind of adjustment that SoCal is advocating, and that in any event, there are a number of factors which tend to offset any imperfections in SoCal's discounting practices embedded within the basic approach SoCal and DRA have used to estimate discount revenue.

SoCal's proposed "practical adjustment" has the effect of reducing the incremental revenue forecast to be obtainable through discounting. It would reduce the percentage of actual industrial volumes used for cost allocation purposes in this proceeding from 99% to 97%. Although the effect of this adjustment is not particularly significant in this proceeding because the amount of discounting is not expected to be great, the percentage change in the discount adjustment is significant and could have dramatic effects in other proceedings where more discounting is forecast. We have considered SoCal's proposed "practical" adjustment and have decided not to adopt this approach. Although there undoubtedly are imperfections in SoCal's negotiation of rate discounts, the discount adjustment can at best only approximate the actual revenue to be gained through discounting, and we are persuaded that it would be better policy to base the discount adjustment upon optimal rather than deficient rate discount negotiation. We also agree with TURN that there are features embedded within the discount adjustment calculation methodology that tend to offset imperfections in SoCal's negotiation of rate discounts. For these reasons, we will adopt DRA's basic approach for calculating the discount adjustment.

5. <u>Throughput Estimates</u>

A number of issues were raised with respect to the throughput forecasts for specific customer classes. These we address in the sections which follow.

a. Noncore Commercial and Industrial

Among the most significant difference between DRA and SoCal throughput estimates were their estimates of noncore commercial and noncore industrial throughput. They forecast the following throughput for these classes:

	Commercial	Industrial
DRA	22.9 MMdth	72.5 MMdth
SoCal	12.6 MMdth	63.8 MMdth

SoCal's forecast would reflect a 6.5% decline in industrial throughput from recorded 1988 levels despite a forecast decline in transport rates (which should increase industrial demand), and only a modest 1% decline in manufacturing employment. DRA's forecast, in contrast, reflects a significant increase in industrial demand.

SoCal attributes the majority of the decline it forecasts in commercial noncore throughput and industrial noncore throughput to an increase in cogeneration. Cogeneration reduces commercial and industrial demand, and increases cogeneration demand. This effect is referred to as the "cogeneration offset factor." Other factors which allegedly account for the decline in noncore commercial and industrial throughput forecast by SoCal are a small decline in industrial employment, and a small shift in employment away from intensive energy facilities.

DRA disputes SoCal's estimate and the company's explanation of the cause underlying its forecast decline in demand. DRA does not believe that SoCal can develop a direct estimate of thermal savings due to cogeneration because SoCals' model does not control for the effects of other changes in the efficiency of energy using capital equipment. Moreover, DRA contends that SoCal's model predicts cogeneration offset effects which are illogical when artificial constraints SoCal placed on the model are removed. Because of these problems with SoCal's model, DRA recommends that the cogeneration offset factors SoCal derived be rejected, and the throughput forecasts of DRA for commercial and industrial noncore be adopted.

CIG also disputes the accuracy of SoCal's cogeneration offset factor. CIG claims that SoCal's cogeneration offset does not explain the decline in commercial and industrial noncore demand reflected in SoCal's forecast.

SoCal attributes the majority of the difference between DRA and company forecasts of noncore commercial and industrial demand to the effects of increased cogeneration, but has not made a persuasive case that it has properly calculated or accounted for the cogeneration effect. The amount of thermal savings due to cogeneration should vary considerably from industry to industry, but SoCal constrained the coefficients on its cogeneration variable to identical values across all three industries in the commercial sector and all eight industries in the industrial sector. When these constraints were removed, at DRA's request, SoCal's model generated dubious results. An increase in cogeneration increases cogeneration gas demand, but reduces process gas demand. Process gas demand is reduced by some percentage reflecting the relative efficiency of the cogeneration unit as compared to the thermal process that it is replacing. Expressed in this manner, the cogeneration offset factor for a particular application, or industry, should generally be a negative number between 0 and -1.0. In some sectors SoCal's model generated positive cogeneration offset factors which indicates that increased cogeneration will increase, rather than decrease the demand for gas for process heat. Furthermore, SoCal used data only through 1987 in developing its forecast. 1988 data was excluded from SoCal's model runs due to alleged concerns about its format and accuracy. When DRA requested that SoCal run its model incorporating 1988 data, the cogeneration coefficients were essentially zero, indicating no thermal efficiency. This result is counterintuitive, and indicates instability in SoCal's model. We are not persuaded that the problem is a result of the data. DRA's model produced consistent results with and without the 1988 data. Incorporating an additional year of data should not result in such significant qualitative changes in model results. Although we prefer DRA's econometric model over SoCal's, and have serious difficulties with SoCal's forecast of the cogeneration offset, we are not persuaded that DRA's forecasts of commercial and industrial noncore demand should be adopted without adjustment. DRA's forecast of noncore commercial and industrial throughput appears somewhat high in light of the inputs assumed. Employment is one of the primary independent variables used by DRA in forecasting commercial and industrial demand. DRA has assumed a 2 percent increase in employment in the commercial sector and a 3/4 percent decrease in employment in the industrial sector during the ACAP period, yet is predicting increases in gas demand of 28 percent for commercial and 10 percent for industrial. DRA attributed this somewhat surprising correlation to a predicted decline in the gas to oil price ratio and a consequent decline in fuel switching. Since we find DRA's forecasts high relative to predicted employment, and since we have also adopted a lower forecast oil price than DRA assumed, we have adopted slightly lower and more conservative values for noncore commercial and industrial throughput than DRA forecast. We forecast 20 MMdth for noncore commercial and 70 MMdth for noncore industrial.

b. <u>Cogeneration (Other than EOR)</u>

DRA forecast cogeneration (other than EOR) throughput of 76 MMdth. SoCal forecast throughput of 73 MMdth for this class. Both estimates were based upon cogeneration capacity data obtained from SCE. SoCal adjusted the data downward by 3.8% to reflect the fact that a portion of the cogeneration included in the SCE data is not gas fired and therefore will not increase gas demand or throughput. DRA did not make this adjustment, but failed to provide any adequate justification for using the unadjusted SCE data.

SoCal's adjustment appears justified. As a result, we will adopt SoCal's forecast of throughput for this class.

c. UEG

DRA forecast UEG demand and throughput of 193.4 MMdth. SoCal forecast demand of 177 MMdth, curtailment of 13.4 MMdth, and throughput of 164.4 MMdth for this class. The difference is due to SoCal's forecast of UEG curtailment, and to the use of different forecast gas and oil prices which results in different conclusions regarding UEG fuel switching. DRA's forecast reflects DRA's expectation that there will be no curtailment or fuel switching during the ACAP period. SoCal forecasts that the gas price will be higher than the price of alternate fuel in January 1990 and as a consequence, forecasts fuel switching during that one month.

SCUPP/IID take issue with the forecasts for LADWP, Burbank, and Pasadena which are included in both the SoCal and DRA forecasts of UEG throughput. SCUPP/IID contend that SoCal failed to properly account for LADWP's Scattergood Unit 3, used outdated data in forecasting LADWP, Burbank, and Pasadena demand, and made several other inaccurate assumptions. SCUPP/IID contend that DRA incorrectly adjusted the demand SoCal assumed for Scattergood Unit 3 to correct for the effects of curtailment, when SoCal had not forecast any curtailment of this unit. SCUPP/IID also take issue with SoCal's forecast UEG igniter fuel volumes.

SCE objects to DRA's throughput forecast on several grounds previously mentioned and in addition, on the ground that DRA UEG gas demand does not reflect the DRA's own cogeneration demand forecast for facilities that sell power to Edison. DRA's forecast of cogeneration demand was approximately 3.8% higher than SoCal's. Increased cogeneration results in decreased UEG demand, but DRA did not take this into account in forecasting UEG demand or throughput.

Forecast oil and gas prices are critical to UEG throughput estimates because UEG customers have an economic incentive to fuel switch anytime that the dispatch price of oil falls below the dispatch price of gas. SoCal's forecast is based upon the company's estimate that LSWR prices in the Singapore market will vary between $13.80 and $14.65/Bbl. Since we have adopted a forecast average price of LSWR of $16.25/Bbl and expect more stability in oil prices over the ACAP period than has been experienced in the recent past, we do not foresee any significant economic fuel switching by SoCal's UEG customers during the ACAP period. To the extent any economic fuel switching may occur, it is likely to occur only during a short period in the winter. We have not attempted to quantify the amount of UEG fuel switching which may occur on SoCal's system because such a forecast does not appear necessary in this proceeding. Fuel switching is likely to occur, if at all, only during the winter which is also the period of time that we have forecast UEG curtailment. Given the differential between our adopted LSWR and spot gas price forecasts, and the difference between our adopted demand and supply forecasts, we expect UEG curtailment to exceed economic UEG fuel switching. Since our UEG throughput forecast already reflects UEG curtailment during the period when economic fuel switching may occur, there is no need to separately forecast the amount of fuel switching.

Since we have adopted DRA's forecast spot gas price, we will in general adopt DRA's UEG demand forecast which was developed using that gas price. We are persuaded, however, that the noncore UEG demand of LADWP should be reduced by approximately 5 MMdth to correct errors cited by SCUPP/IID. We will adopt a demand forecast for LADWP of 47 MMdth. We are not persuaded of the necessity to adjust the throughput forecasts for Burbank or Pasadena. SoCal's forecast of UEG igniter fuel volumes was not adequately supported. As a result, we will adopt SCUPP/IID's forecasts of UEG igniter fuel volumes for its members. Since we have not adopted DRA's cogeneration forecast, we do not find any adjustment to SCE's UEG demand necessary.

We will adopt a UEG throughput forecast of 152.6 MMdth. This value has been derived from the DRA's forecast of UEG demand adjusted to correct errors cited by SCUPP/IID (188.4 MMdth), less our forecast level of UEG curtailment (35.9 MMdth).

d. <u>EOR Steaming and Cogeneration</u>

DRA and SoCal agree on a forecast of 122 MMdth for enhanced oil recovery (EOR) cogeneration demand and throughput. They disagree, however, in their forecasts of EOR steaming demand and throughput.

DRA forecasts EOR steaming demand and throughput of 38.7 MMdth, while SoCal forecasts demand of 24.4 MMdth and throughput of 20.1 MMdth. The difference in the estimates is due to two factors: (1) their use of different oil and gas price forecasts with resulting differences in forecast fuel switching, and (2) different assumptions concerning EOR steaming curtailment. SoCal forecasts some fuel switching, whereas DRA forecasts no fuel switching. SoCal forecasts EOR curtailment of 4.3 MMdth, while DRA forecasts no curtailment.

Based upon the gas and oil price forecasts we have adopted, we conclude that there should be no significant economic EOR fuel switching. To the extent that any economic fuel switching may occur, it is likely to occur only during a short period in the winter. For the reasons discussed more fully above, we expect any fuel switching to be offset by EOR steaming curtailment. As a consequence, we have not attempted to quantify the amount of EOR fuel switching which may occur.

Since we have adopted DRA's forecast spot gas price, and because we expect any EOR fuel switching to be offset by curtailment, we will adopt DRA's EOR demand forecast. Based upon these assumptions, we will adopt an EOR throughput forecast of 150.9 MMdth. We have derived this value by taking DRA's forecast of total EOR demand and reducing it by our forecast level of EOR steaming curtailment (9.8 MMdth).

e. Wholesale

(1) SDG&E

DRA, SoCal, and SDG&E developed estimates of SDG&E demand. Their estimates were similar for non-UEG, but differed markedly for UEG. The different estimates were in summary:

	Non-UEG	UEG
DRA	69.2 MMdth	38.4 MMdth
SoCal	72.2 MMdth	35.1 MMdth
SDG&E	68.8 MMdth	20.1 MMdth

The difference in the UEG forecasts is due to the parties' use of different forecast oil and gas prices, which produce different levels of forecast economic fuel switching. DRA assumed no fuel switching. SoCal assumed three months of fuel switching. SDG&E assumed six months of fuel switching.

As discussed in more detail below, since we have adopted a higher price for oil and a lower price for gas than SoCal and SDG&E, we forecast far less economic fuel switching than either company. We have not attempted to quantify the amount of fuel switching which may occur because fuel switching is likely to occur only during the peak winter months, which is a period of time during which we have forecast UEG curtailment. We have assumed, for purposes of this proposed decision, that UEG curtailment will equal or exceed economic fuel switching. Significant fuel switching by SDG&E UEGs is far more likely than by other SoCal customer classes though. This is because of a slightly higher gas price assumed for SDG&E and a lower oil price (due to SDG&E's ability to use less expensive higher sulfur content oil (LSFO)). We recognize the possibility that the models run by DRA, SoCal, and SDG&E to forecast fuel switching may produce results which differ from our assumption that curtailment will offset fuel switching. As a consequence, we will permit any of the parties whose models have been explored on the record in this proceeding to include an attachment with their comments, a summary of the amount of fuel switching their model predicts using our adopted oil, gas, demand, and curtailment values. We will consider any such information offered, together with the record testimony on tho models used, prior to issuing a final decision in this proceeding.

With the caveat mentioned, we will adopt a throughput forecast for SDG&E of 101 MMdth, based upon DRA's demand forecast less the level of curtailment we expect SDG&E to experience during the ACAP period (8.0 MMdth).

(2) Long Beach

DRA and SoCal agree on Long Beach demand: UEG demand of 18.3 MMdth, non-UEG demand of 10.2 MMdth, and total demand of 28.5 MMdth. DRA and SoCal also appear to be in agreement that Long Beach should be allocated a proportional share of any necessary UEG curtailment, assuming the adopted demand and supply forecasts require curtailment of UEG customers. Long Beach has, however, contested the proportional allocation of UEG curtailment.

Long Beach has argued that the adopted throughput to Long Beach should not be reduced below the forecast level of demand to reflect partial curtailment of P-5 requirements. The basis of its contention is that Commission decisions, and SoCal's tariff, permit "capacity curtailment" only when there is a shortage of capacity on SoCal's own facilities. Long Beach contends that there is no record evidence that SoCal lacks sufficient capacity on the southern portion of its system to meet all Long Beach demand. On this basis Long Beach argues that it should be allocated no curtailment, and no curtailment of Long Beach demand should be forecast.

Long Beach's argument is dependent upon questions of tariff interpretation, and to adopt it in practice would require changes in SoCal's current curtailment practices. The issues raised by Long Beach, while intriguing, are beyond the scope of this ACAP proceeding. They should be considered in the context of a proceeding such as Long Beach has recently initiated through its petition to modify D.86-12-010.

We have forecast that curtailment will occur on SoCal's system inspite of the maximum possible use of available supplies and system capacity. When conditions requiring curtailment arise, SoCal will be required to meet the requirements of its system demand according to established curtailment practices and policies. This will be required regardless of whether the conditions requiring curtailment are characterized as "capacity curtailment" or "supply curtailment." Until SoCal's curtailment practices are reviewed and modified, if in fact that is the future result of Long Beach's petition, we are not persuaded that Long Beach's explication of SoCal's tariff and prior Commission decisions warrants excluding Long Beach from a prorata portion of the curtailment we have forecast.

We will adopt a throughput forecast for Long Beach of 23.9 MMdth based upon forecast curtailment of 4.6 MMdth.

6. <u>Cold Year Throughput</u>

Cold year throughput is one of the bases used for the allocation of system costs. SoCal contends that throughput is constrained by system capacity, and that as a result, incremental cold year demand merely results in additional curtailment over and above what the company forecasts under average year conditions. TURN contends that system capacity exceeds average year demand and that SoCal should be able to serve 20 MMdth of additional demand under cold year conditions. TURN concedes that any additional cold year demand above this level would lead to curtailment. DRA originally forecast sufficient additional capacity through interutility sales to avoid any cold year curtailment, but later accepted TURN's cold year forecast.

We forecast curtailment under our adopted average year demand and gas supply forecasts. Our adopted cold year throughput simply reflects curtailment of the incremental cold year demand.

B. Cost of Gas

Gas costs must be forecast in order to establish bundled core rates, and for use in forecasting noncore demand. Noncore rates are developed monthly on the basis of current prices and are not established in the ACAP. Various elements of SoCal's payments to pipelines, which represent part of the cost of gas, must also be forecast so that they may be allocated to various customer classes.

1. Core WACOG

The gas portfolio for core customers contains all long-term supplies and any short-term supplies needed to meet forecast core demand. SoCal's proposed core portfolio consists of natural gas from the following sources: California production, Federal offshore production, Pacific Offshore Production Company (POPCO), Pacific Interstate Transmission Company (PITCO), pipeline and direct purchases via the Transwestern and El Paso systems, and spot gas purchases.

The DRA recommends adoption of a core weighted average cost of gas (WACOG) of $2.36/MMBtu (after adjustment for Minimum Purchase Obligation (MPO) transition costs) for the ACAP period. SoCal recommends adoption of a core WACOG of $2.46/MMBtu (also after adjustment for MPO transition costs). SoCal and DRA were the only parties to forecast the core WACOG. The difference between DRA and SoCal is a result of higher price estimates by SoCal of five of the six sources of supply, and slight differences in the volumes of gas forecast to be taken from several of the sources of supply.

For the reasons discussed below, we adopt a core WACOG of $2.36/MMBtu for the ACAP period.

a. <u>California</u>

SoCal estimates that California production will account for approximately 605 MMth of gas during the ACAP period and forecasts a weighted average price of $2.53 MMBtu for this supply. DRA accepts SoCal's forecast, but has raised questions about the form of SoCal's California contracts, and its purchases of Elk Hills gas.

Gas purchased from Elk Hills is purchased from the U.S. Department of Energy through a competitive bidding process every four months and is included in SoCal's forecast of California production. SoCal expects to take a significant portion of its California source gas, 104 MMth, from Elk Hills at a forecast price 40 cents/Dth above the forecast price of spot gas. Long Beach, TURN, DRA, and CIG/CLFP all question whether Elk Hills should be considered a firm supply for core customers, and whether SoCal should be paying such a premium for it.

We share these concerns, and as a result, have assumed that any gas purchased from ElK Hills during the ACAP period will be purchased at a weighted average price equal to the core WACOG.

We will adopt a forecast of 605 MMth at weighted average price of $2.48 MMBtu for California production.

b. <u>Federal Offshore</u>

SoCal and DRA both estimate that 42 MMth of federal offshore gas will be taken during the ACAP period. SoCal estimates a weighted average price of $3.48/MMBtu, whereas DRA estimates a price of $3.42/MMBtu. Since most federal offshore gas is indexed to Natural Gas Policy Act (NGPA) price categories, SoCal assumed that the price for all federal offshore gas will escalate in the future at an assumed inflation rate. DRA reviewed the recorded price of this supply since 1986 and found that the total price for this gas has actually decreased during this period. In light of this analysis, DRA assumed that the total weighted average price of federal offshore gas will remain the same during the ACAP period as during the past year.

We find DRA's price forecast more persuasive, and have adopted 42 MMth at a weighted average price of $3.42 for this supply.

c. PITCO

Both the DRA and SoCal have forecast that SoCal will take 835 MMth from PITCO at a weighted average price of $2.30/MMBtu. We will adopt these forecasts.

d. POPCO

SoCal estimates that it will take 105 MMth of POPCO gas at a weighted average price of $2.80/MMBtu. DRA estimates 114 MMth at a price of $2.65/MMBtu.

DRA reviewed recorded POPCO prices and volumes over the past 30 months and found that the total average price paid for POPCO gas by SoCal has generally been decreasing. To estimate POPCO deliveries and prices for the ACAP period, DRA assumed that both deliveries and price would be comparable to last year. DRA also estimated the take-or-pay surchage applicable to these purchases based upon the recent Federal Energy Regulatory Commission (FERC) order approving uncontested settlement. SoCal appears to have made an error in calculating the effect of the FERC order which accounts for a significant portion of the difference between DRA's and SoCal's price forecast.

We find DRA's estimate more persuasive, and as a result have adopted 114 MMth at $2.65/MMBtu for this supply.

e. Interstate Pipeline and Direct Purchases

SoCal estimates that it will take 2420 MMth from direct purchases and pipeline supplies via the Transwestern and El Paso systems at a weighted average price of $2.52/MMBtu. DRA forecasts southwest supplies of 2466 MMth at a weighted average price of $2.42/MMBtu.

Pipeline and direct interstate purchases via the Transwestern and El Paso systems represent the major core supply source for the ACAP period. These sources are forecast to provide approximately 58% of the core supply. Most of this gas has been acquired over the past year under a variety of one year direct purchase contracts which expired in October. SoCal anticipates obtaining this supply under similar contracts during the ACAP period. Because SoCal's prior contracts expired, and new contracts had not yet been negotiated at the time of hearings in this proceeding, the actual volumes of gas and the prices to be paid for these supplies were unknown. Because of these uncertainties, neither SoCal nor DRA attempted to develop specific forecasted volumes or prices for the different components represented by this supply category. Both company and DRA forecast supply and price in an aggregate fashion upon the basis of rather general assumptions.

SoCal's estimate of the aggregate price for direct purchases and/or pipeline supplies is based on the assumption that the price for this supply will, in the aggregate, increase during the ACAP period by half as much as the company forecast spot gas prices to increase during the ACAP period. This assumption was based upon SoCal's view that gas demand and supply are gradually coming into balance.

DRA accepted SoCal's assumption, that the price for these supplies will increase half as much as spot gas prices, but not necessarily SoCal's underlying rationale. The difference in SoCal's and DRA's forecast price is a result of DRA's lower forecast spot gas price.

Forecast volumes of direct and pipeline purchases are a function of the forecast of core demand. As a result, we have adopted a forecast consistent with our adopted core demand. The forecast price for these supplies is a function of the forecast spot gas price, and since we have adopted DRA's spot gas forecast, we will adopt DRA's forecast price for these supplies. The adopted volume and price for these supplies are: 2548.1 MMth at a weighted average price of $2.42/MMBtu.

f. Spot Gas

DRA has accepted SoCal's estimate that it will take 596 MMth of spot gas for the core portfolio. Our adopted spot gas border price of 2.19/MMBtu equates to a weighted average price of $2.22/MMBtu for these supplies.

2. Noncore WACOG

The gas portfolio for noncore customers, consistent with D.87-12-039, contains only short-term supplies with prices that are firm for up to 30 days. SoCal estimated that it will take 2064 MMth of short-term supplies for noncore customers at a weighted average cost of $2.41/MMBtu during the ACAP period. DRA estimated that 2521 MMth at a weighted average cost of $2.20/MMBtu. The difference in supply forecasts reflects differences in the parties estimates of noncore demand and SoCal's assumption that there will be some noncore curtailment during the ACAP period. Both price estimates are based upon the parties' respective estimates of spot gas prices, but also reflect a difference in the way the parties have accounted for PG&E interutility transportation costs. SoCal has included these transportation costs in its estimate of the noncore WACOG, while DRA has treated them as a debit to interutility revenues.

The adopted level of noncore supply is a value which results from the forecast gas demand and supply we have adopted, and the resulting level of forecast curtailments. Based upon the supply and demand forecasts we have adopted, we forecast noncore supply of 2075.3 MMth. We will adopt the DRA's recommended noncore WACOG of $2.20/MMBtu since it reflects the spot gas cost we have adopted. We also will adopt DRA's accounting treatment for PG&E interutility transportation revenue which is reflected in this adopted value.

3. Transition Costs

In D.87-12-039 we determined that certain unavoidable costs which were incurred for the benefit of all ratepayers prior to December 3, 1986, should be considered transition costs and should be recovered from all customers. We identified four criteria which should be met for transition cost treatment. We stated that a cost item would be considered a transition cost if it resulted from a gas purchase contract, tariff, or arrangement which:

1. Took effect before December 3, 1986;
2. Was incurred for the benefit of all ratepayers;
3. Was intended to be recouped from all ratepayers; and
4. Now results in costs in excess of a currently reasonable level.

A number of issues arose in the proceeding concerning costs which were alleged to be within the definition of transition costs. These are discussed in the sections which follow.

a. Excess Purchased Gas Costs

DRA contested the treatment of $6,771,000 in "excess" purchased gas costs as transition costs. The costs at issue were allegedly incurred by SoCal for the purchase of gas in 1986-87 and 1987-88 in order to avoid curtailment of P3B, P4, and UEG customers. These costs are currently at issue in SoCal's pending reasonableness reviews for 1986-87 (A.87-12-057) and 1987-88 (A.88-07-006). Since no decision has yet been issued in the consolidated reasonableness review proceeding, the issue raised by DRA concerning the manner in which such costs should be allocated will be deferred to SoCal's next ACAP.

b. Minimum Purchase Obligation Costs

In D.87-12-039 we determined that there are minimum purchase obligation (MPO) costs associated with the POPCO and California supplies which should be considered transition costs. DRA and SoCal have estimated these MPO transition costs and generally agree on the manner in which they should be estimated. The differences between the DRA and company estimates generally are due to different forecast prices for the different price components that make up the MPO costs. DRA, TURN, and Long Beach have, however, raised objections to considering excess costs of Elk Hills purchases as MPO transition costs.

Elks Hills gas is part of the supply SoCal intends to purchase for the core porfolio. The price SoCal forecasts for Elk Hills purchases exceeds SoCal's forecasted core WACOG by approximately 20 cents/Dth. On the basis of transition cost principles adopted in D.87-12-039, SoCal has proposed assigning this gas to the core portfolio at the core WACOG price and classifying the difference between the cost of Elk Hills gas and the core WACOG as a minimum purchase obligation (MPO) transition cost. Classified in this manner, the excess cost of Elk Hills gas would be paid for by all customers; core customers would pay the core WACOG for Elk Hills gas while all customers (including the core) would pay the excess cost.

Long Beach, TURN, and CIG/CLFP object to this treatment. They argue that Elk Hills purchases are discretionary purchases made through a competitive bidding process every four months, and that it is not a secure long-term supply and should not be included in the core portfolio. If this supply was replaced by spot gas or other short-term gas, core customers would presumably benefit from reduced gas costs, and noncore customers would be spared the additional MPO transition costs. DRA concurs.

In response to these arguments, SoCal has recommended that the Commission defer any decision on the reasonableness of Elk Hills purchases, and simply assume that SoCal will pay a price equivalent to the core WACOG for this supply. If this approach is adopted, SoCal would recover the amount, if any, above the core WACOG through the core gas cost balancing account and through the noncore transition cost tracking account. Determination of the reasonableness of these purchases, and whether any amount paid above the core WACOG should be treated as transition costs could then be deferred until it was known whether any such excess cost was paid.

We agree, for the reasons stated by TURN, Long Beach, and CIG/CLFP that the forecast price of Elk Hills should be assumed to be equivalent to the core WACOG. We also agree with SoCal that the reasonableness of any purchases of Elk Hills gas above the core WACOG should be considered in SoCal's annual reasonableness review and not in this ACAP. Issues concerning management prudence or reasonableness are not appropriate for consideration in ACAP proceedings. Although Elk Hills gas may be purchased by SoCal, we make no judgement about the reasonableness of such purchases.

We have included such supplies in the supply forecast for purposes of this ACAP at the adopted core WACOG price. Consistent with this decision, we will assume no excess costs from Elk Hills purchases and no MPO transition costs associated with Elk Hills purchases. We feel we should also provide guidance on the question of transition cost treatment for these purchases. In our opinion, Elk Hills purchases do not meet the definition of transition costs established in D.87-12-039 and should not receive transition cost treatment on that basis. We have not considered or decided, however, whether excess costs associated with Elk Hills purchases should for other reasons be allocated in a manner consistent with our treatment of transition costs. This issue should be addressed in a future proceeding if and when SoCal requests such treatment.

We will adopt MPO costs consistent with the price forecasts we have adopted for the different components that makeup this cost element.

c. <u>Direct Billed Take-or-Pay Costs</u>

Take-or-pay costs are amounts billed to SoCal from interstate pipelines as a result of various orders of the FERC which allocate take-or-pay buydown and buyout costs arising from uneconomic contracts between interstate pipeline companies and gas producers. Direct billed take-or-pay costs are distinguished from volumetric take-or-pay costs. Direct billed take-or-pay costs are billed directly to pipeline customers on the basis of their historical purchases. Volumetric take-or-pay charges are applied as a surcharge on every unit of current pipeline throughput. In this proceeding, only the treatment of direct billed take-or-pay costs is a significant issue.

A number of issues were raised concerning direct billed take-or-pay costs. They are generally related to either the amount that should be forecast for different take-or-pay amounts, or to the question how such costs should be allocated. Disagreements concerning forecast amounts were resolved prior to the conclusion of the hearings. Allocation, however, was perhaps the most hotly contested issue in the proceeding.

(1) <u>Forecast Take-or-Pay Amounts</u>

A number of disagreements were raised initially concerning the forecast of take-or-pay amounts, but they have since been resolved by the parties. In summary, the parties have agreed to the following forecast amounts.

SoCal accepts DRA's forecast of $30,668,000 for El Paso take-or-pay billings for the ACAP period, and $14,705,000 for El Paso take-or-pay billings prior to October 1, 1989. SoCal has also agreed to DRA's forecast of take-or-pay amounts billed by Transwestern before October 1, 1989 of $47,370,000. There are no forecast direct billed Transwestern take-or-pay liabilities for the ACAP period since all these amounts will have been paid prior to October 1989. And, finally, SoCal also accepts DRA's forecast of take-or-pay amounts billed by POPCO before October 1, 1989 of $625,000. The payment previously made by SoCal to POPCO reflected in the CAM account should be adjusted to reflect the actual payment.

(2) Allocation of Take-or-Pay Charges

(a) Background

The circumstances that gave rise to the gas industry's take-or-pay problems are well explained in FERC decisions, particularly FERC Order No. 436, and Order No. 500. We take notice of the findings and conclusions of the FERC reached in these decisions.

The take-or-pay costs now at issue in the industry arose as a result of contracts entered into in the late 1970's and early 1980's. This was a period of gas shortages and rising prices. During this period, pipeline companies attempted, with the encouragement of the FERC, to maintain secure long-term supply reserves. They often negotiated and signed contracts of 10 years or more. These contracts commonly included "take-or-pay" provisions. These provisions required the pipelines to pay for a specified percentage of the contract quantity of gas even if the pipelines took less. The often high cost of gas under these contracts had little initial effect on the marketability of the gas because the cost was rolled-in to the pipelines' computed average cost of gas along with other low price price-controlled gas for ratemaking purposes, thereby keeping it competitive with the cost of alternate fuels and interstate pipelines had take-or-pay commitments from their customers guaranteeing pass through of gas costs. Elimination of customers' take-or-pay obligations in FERC Order No. 380, and a drop in the price of alternate fuel eventually brought the embedded cost of these long term take-or-pay contracts well above competitive prices. By 1985, pipeline companies found themselves committed to purchase significant volumes of high priced gas in what was then a period of falling prices and increasing competition between gas and other alternate fuels. Inspite of the growing competition at the wellhead, interstate pipelines still retained market control over gas transportation. They reacted to their growing predicament by refusing to transport third party gas when to do so would have the effect of displacing the pipeline companies' own deliveries. This discrimination in transportation had the effect of denying consumers access to gas at the lowest reasonable rate, but preserved much of the pipelines' market for what would otherwise have been uneconomically priced gas.

In Order No. 436 the FERC addressed the growing disparity between wellhead and pipeline prices in a comprehensive manner. The FERC concluded that the prevailing pipeline practice of generally refusing to transport gas for third parties where to do so would displace their own sales, had caused serious market distortions. It found this practice "unduly discriminatory" within the meaning of § 5 of the Natural Gas Act, 15 U.S.C. §§ 717 et seq. (NGA), and ordered a radical restructuring of the industry. Pipelines' transportation and mechandising roles were unbundled and pipelines were required to transport gas for third parties in competition with the pipelines' own supplies.

This decision resulted in significant new competition in the industry, particularly between pipelines and other gas sellers (producers and marketers), and provided consumers with the economic benefits of more competitive wellhead prices.

These changes did not occur, however, without significant repercussions in the industry. Among the more problematic of these is the present industry take-or-pay problem. As pipeline customers took advantage of the new open access rules, the pipelines found it increasingly difficult to market gas that had been contracted for under long-term contracts at high prices. The pipelines' high priced supplies became unmarketable as more and more pipeline customers chose to purchase their own gas directly from producers or marketers for transportation. This resulted in drastic reductions in pipeline takes of high priced gas, and significant liability under the pipelines' take-or-pay contracts with gas producers.

FERC took no action in Order No. 436 to relieve pipelines of their take-or-pay obligations under high-priced contracts or to otherwise resolve the take-or-pay problem. On appeal, the United States Court of Appeals, in Associated Gas Distributors v. FERC, 824 F.2d 981 (D.C. Cir. 1987), upheld the substance of the FERC's restructuring of the industry, but found problems with the FERC's failure to deal with the take-or-pay issue. The Court remanded the case to the FERC for further proceedings on the take-or-pay problem.

Those further proceedings culminated in FERC Order No. 500. Order 500 is intended by the FERC to substantially mitigate the effects of Order No. 436 on pipeline take-or-pay problems. Among the steps FERC took in Order 500 to address the problem was the adoption of two alternative mechanisms for pipelines to use to recover prudently incurred take-or-pay related costs. Under the first option, pipelines may recover 100% of prudently incurred costs through volumetric or commodity rates. The second option has been referred to as an "equitable sharing" mechanism. Under this option, pipelines are permitted to recover anywhere from 25% to 50% of their take-or-pay costs from customers through a fixed take-or-pay charge direct billed to pipeline customers, provided that the pipeline agrees to absorb an equal amount. Any amounts above what the pipeline is willing to absorb would be permitted to be recovered through a commodity surcharge, or volumetric surcharge, on pipeline throughput.

The costs incurred by El Paso and Transwestern to buyout and buydown their accrued take-or-pay liability with producers are the costs subject to recovery through the alternative mechanisms provided for in Order 500. Both El Paso and Transwestern have chosen FERC's "equitable sharing" approach and have chosen to allocate 25% of their take-or-pay costs to their shareholders and the remaining 75% to their customers. Of the remaining 75%, 1/3 (i.e., 25% of the pipelines' total liability) is recoverable through direct billing, and 2/3 (50% of the pipelines' liability) is recoverable through a volumetric surcharge applicable to total pipeline throughput.

(b) Positions of the Parties

Against this background, the proposals of the parties concerning the disposition of take-or-pay costs at issue in this proceeding must be considered. Only the 25% of pipeline take-or-pay costs direct billed are at issue. No party has challenged the recovery of the 50% of take-or-pay costs the pipelines are recovering through volumetric surcharges.

Three parties made specific proposals regarding SoCal's recovery of direct billed take-or-pay costs: SoCal, DRA, and Salmon/Mock.

SoCal claims that it is entitled to recover 100% of all take-or-pay costs, and proposes to recover the noncore portion through demand charges with full balancing account protection.

Edison supports SoCal and alleges that utilities are entitled to an opportunity to recover all of their costs unless proven unreasonably incurred.

PG&E and SDG&E also support SoCal.

DRA recommends that the Commission adopt an equitable sharing mechanism similar to that adopted by the FERC. In support of its recommendation DRA adopts the rationale of the FERC that the causes of the pipelines' take-or-pay problems are many and complex, that it is difficult to assign blame, and that all segments of the industry should shoulder some of the burden of resolving the problem. DRA recommends that the Commission permit SoCal to choose between two different methods of recovery: (1) recovering all take-or-pay costs through a volumetric surcharge without balancing account protection, or (2) recovering, through a direct billed demand charge, four times the percentage of direct billed take-or-pay costs that the company agrees to absorb. Under the second option, any remaining balance, after 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.

TURN is in general agreement with DRA and notes that DRA's recommendation is essentially the same as advocated by TURN prior to D.87-12-039. TURN supports its recommendation on the principle that the costs of resolving the problem should be allocated equitably among all segments of the industry.

> "(A)ll of the other sectors of the gas industry--producers, pipelines and end users--have been forced to make sacrifices and bear what they viewed as unreasonable costs in order to move forward with the transition to the new industry structure. The one glaring exception to this 'share the pain' policy thus far has been the local distribution utilities such as SoCal, who have paid nothing and borne no risks while others have suffered. Clearly, the time has come to remedy this blatant inequity. While this exception is sure to be met with cries of 'it wasn't our fault,' that argument has not been sufficient to spare any other party from bearing a portion of these costs." (Exhibit 80 (TURN/Florio), pp. 27-28.)

TURN supports DRA's recommendation with the proviso that in the event SoCal elects not to absorb any of the take-or-pay costs, there should be no balancing account coverage for the portion of take-or-pay costs allocated to the core market.

Salmon/Mock object to SoCal recovering any direct billed take-or-pay costs. They allege that the only way to effect a truly equitable sharing of these costs is to require SoCal to absorb all amounts billed in excess of the amount that the FERC permits the pipelines to recover through volumetric charges. Salmon/Mock would permit the portion of take-or-pay costs reflected in pipeline volumetric rates to be fully passed through to ratepayers, but would preclude recovery of any and all direct billed amounts. SCUPP/IID, and DGS support the proposal of Salmon/Mock.

In response to the proposals of DRA and Salmon/Mock, SoCal offered in evidence testimony concerning the reasonableness of the company's practices with respect to interstate purchases and the absence of company responsibility for the incurrence of take-or-pay costs. The ALJ ruled this testimony inadmissible on grounds that the reasonableness of SoCal's actions is not the basis of the recommendations of DRA or Salmon/Mock, and is not an issue properly within the scope of an ACAP proceeding. The ALJ further noted that issues concerning reasonableness are, under the Commission's current regulatory framework, appropriate to raise in annual gas utility reasonableness review proceedings. Consistent with this ruling, the ALJ indicated that the recommendations of DRA, TURN, and Salmon/Mock could only be judged, in this proceeding, on the basis of policy considerations other than the reasonableness of SoCal's actions. SoCal took exception to the ruling, and requested that its testimony on reasonableness excluded from evidence be received as an offer of proof. This motion was granted.

In support of its request for full recovery of take-or-pay costs, SoCal argues that Salmon/Mock's recommendation would result in a substantial disallowance and is totally inconsistent with FERC Order 500. SoCal interprets Order 500 to provide alternative means of recovering take-or-pay costs, and provides no basis for disallowing recovery of prudently incurred costs by local distribution companies. The company also argues that take-or-pay liability arose out of interstate pipelines' contracts with their gas suppliers and that SoCal was not a participant in pipeline-producer negotiations, and therefore not responsible for the contracts which gave rise to the problem. SoCal also argues that it is entitled to recover costs that the Commission has previously authorized to be booked to a tracking or balancing account for later recovery, and that such costs cannot later be disallowed because the Commission has changed its mind about recovery after the expenses have been incurred and booked. SoCal also argues that the Salmon/Mock proposal would violate the principle discussed in <u>Nantahala Power & Light Co. v. Thornberg</u>, 476 U.S. 953 (1986) and <u>Mississippi Power & Light Co. v. Mississippi</u>, 101 LEd 2d 322, __ U.S. __ (1988) that amounts allowed by a federal regulatory agency to be billed by a federal-jurisdiction utility to a local utility must be allowed in the local utility's rates by state regulators. SoCal asserts that the holdings of these cases, as applied to FERC authorized interstate pipeline take-or-pay charges, require 100% pass-through at the state level. Finally, SoCal argues that it would be clear legal error for the Commission to impose a disallowance on the company without having allowed the company to put in evidence testimony clearly relevant to this issue.

In response to SoCal's arguments, DRA and TURN note that FERC explicitly stated that it was not prescribing the method by which take-or-pay costs were to be recovered at the state level. As a result of this explicit statement of the FERC, DRA, and TURN allege that no federal preemption problem exists.

CIG/CLFP supported Salmon/Mock in their opening and reply briefs, but filed a motion on August 1, 1989 to defer consideration of take-or-pay costs to a subsequent phase of this proceeding. CIG/CLFP seeks an opportunity to more fully develop the record on this issue. CIG/CLFP alleges that there was little or no testimony concerning the basis upon which the take-or-pay costs were incurred, and insufficient time for the parties to prepare rebuttal testimony in response to the rebuttal offered by SoCal on July 26, 1989, and that as a consequence, the record in this proceeding is inadequate to permit the Commission to decide allocation questions concerning take-or-pay costs.

(c) Discussion

Whether the take-or-pay costs which SoCal seeks to recover were reasonably incurred is not at issue in this proceeding. We do not view the testimony of DRA or Salmon/Mock as contesting the reasonableness of the costs at issue, and even if we did, we would not address the issue in this proceeding. ACAPs are not the proper forum for consideration of management prudence or reasonableness. Under the Commission's regulatory program for gas utilities, reasonableness must be considered in annual utility reasonableness review proceedings. The ALJ was correct in striking SoCal testimony on this issue. The only take-or-pay issues properly before the Commission in this ACAP proceeding are issues related to the allocation of costs.

CIG/CLFP has requested that we defer consideration of these allocation issues. We will deny the motion. Parties to this proceeding have been on notice at least since we issued D.87-12-039 on December 9, 1987 that the allocation of take-or-pay costs would be an important issue to resolve in future ACAP proceedings. Parties have also been on notice since April 12, 1989 when SoCal's application was filed, that the company was requesting full recovery of all take-or-pay costs from its customers. While we have no doubt that a more extensive record could be developed, there has been no showing of good cause for deferring the issue, and no showing that the present record on this issue is deficient in any essential or even important respect. We will address the allocation issues presented.

SoCal has requested regulatory treatment which, in effect, assigns full responsibility for the economic and regulatory risks which gave rise to take-or-pay liability, and the consequential costs now being assessed, to its ratepayers. Under the circumstances, it is difficult to justify such a result. After extensive review of the industries' problems the FERC stated,

> "The Commission recognizes that it is difficult to assign blame for the pipeline industry's take-or-pay problems. In brief, no one segment of the natural gas industry or particular circumstance appears responsible for the pipelines' excess inventory of gas. As a result, all segments should shoulder some of the burden of resolving the problem." (Order No. 436, III FERC Stats. and Regs., Paragraph 30,761 at p. 30,779.)

> "...there should be an equitable sharing of take-or-pay costs among all segments of the industry, including producers, pipelines, distributors and consumers." (Order No. 500, III FERC Stats. and Regs., Paragraph ________.)

We agree with the FERC that no one segment of the industry appears responsible for the problem. We also agree with the FERC that, under the circumstances, all segments of the industry, including distributors such as SoCal, should share some portion of the burden necessary to resolve the problem.

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.

In defense of the right to recover take-or-pay costs, SoCal and Edison contend that utilities are entitled to recover all costs incurred except such costs as are found to have been due to management imprudence. This argument is contrary to well established case law (see e.g., Duquesne Light Co. v. Barasch (1989) __U.S.__, 102 LEd2d 646 and cases discussed therein), and is premised upon a fundamental misunderstanding of utility regulation. Management imprudence can certainly be the basis for the disallowance of costs for ratemaking purposes and can affect the earned return of utilities, but it is equally true that the costs of unforeseen events, such as those which gave rise to the take-or-pay problems of the gas industry, can also affect earned return. Utility regulation is a substitute for free market competition, and although regulation has relieved utilities of substantial economic and competitive risks, it was never intended to relieve utilities of all of the risks inherent in competitive or regulated markets. Risk is inherent in doing business even as a regulated utility. And more importantly, this risk is recognized in the rate setting process. Regulators are in fact required by law to set rates so as to provide utilities with a reasonable opportunity to earn a return commensurate with returns on investments with similar risks. (See FPC v. Hope Natural Gas Co. (1944) 320 U.S. 591, 603.) The law does not guarantee that utilities will earn the return authorized, however, (see Hope, supra. 320 U.S. at 603), and certainly does not require utility ratepayers to shoulder 100 percent of the economic burden of unforeseen events. (Compare e.g., Duquesne Light Co. v. Barasch (1989) __U.S.__, 102 LEd2d 646 upholding a rate base disallowance of costs associated with a cancelled nuclear power plant without any finding of management imprudence. On the contrary, the manner in which utility rates are set generally contemplates that unforeseen events will, from time to time affect company earnings, and will sometimes cause earned return to fall below what was authorized. Utilities are routinely compensated for this very risk. The rates of return granted utilities in each general rate case include allowances to compensate utilities for economic and regulatory risks, including unforeseen risks.

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.

SoCal, Edison, and PG&E have argued that any ratemaking treatment short of 100% recovery of take-or-pay costs would violate the holdings of Nantahala Power & Light Co. v. Thornberg, 476 U.S. 953 (1986) and Mississippi Power & Light Co. v. Mississippi, 101 LEd 2d 322, __ U.S. __ (1988). They argue that these cases require 100% pass-through of FERC approved costs at the state level, and that since the take-or-pay costs at issue have been approved by the FERC, they must be passed through to SoCal's customers by this Commission.

We disagree. SoCal, Edison, and PG&E have failed to recognize that the FERC's decision approving take-or-pay costs explicitly provides for, and encourages, an equitable sharing of costs between local distribution companies, such as SoCal, and their customers. The FERC stated:

> "(T)he proposed policy statement does not attempt to prescribe the methods by which approved pipeline take-or-pay costs are to be allocated at the state level. However, it is the Commission's view that there should be an equitable sharing of take-or-pay costs among all segments

> of the industry." (III FERC Stats. and Regs. at p. 30,790.)

Clearly the FERC has not prescribed the methods by which this Commission should allocate SoCal's take-or-pay costs, and that is the only take-or-pay issue that we are addressing in this decision.

SoCal has also argued that costs the Commission has authorized to be booked into tracking or balancing accounts cannot be disallowed from recovery by the Commission after the expenses have been incurred. Since the Commission has previously authorized take-or-pay costs to be booked to SoCal's Core Fixed Cost Account and Noncore Fixed Cost Account, SoCal argues that the Commission has no option now but to allow full recovery.

We disagree. SoCal has completely misconstrued the nature of tracking and balancing accounts and misconstrued our earlier decision authorizing take-or-pay costs to be booked to the Core and Noncore Fixed Cost Account. Balancing and tracking accounts are always established for the explicit purpose of facilitating further rate adjustments, and often further review of the costs booked to such accounts. In many cases, such accounts have explicitly been made subject to future reasonableness review and, by clear implication, potential disallowance of costs after they have been incurred and booked. Moreover, recovery of take-or-pay costs booked to the Core and Noncore Fixed Cost balancing accounts was explicitly made subject to future regulatory review by the Commission in D.87-12-039.

A more difficult problem is determining an appropriate allocation of take-or-pay costs, given the principle that the risks and costs can and should be shared by distribution companies as well as their customers. Again, we consider the FERC's findings instructive.

Under the FERC's adopted alternative allocation mechanisms, pipelines have been given a choice. They may choose to recover take-or-pay related costs through a volumetric surcharge, or they may recover a percentage through direct billings equal to the percentage they are willing to absorb. The former course provides pipelines with a theoretical opportunity to recover all take-or-pay costs, but also entails risk. Market forces are likely to limit recovery of take-or-pay charges through volumetric rates. The alternative "equitable sharing" mechanism, provides pipelines with a certain writeoff, in exchange for certain recovery of a portion of the costs. Both El Paso and Transwestern have elected the latter option, and have chosen to absorb 25% of their take-or-pay costs. This leaves 50% to be billed through volumetric charges, and 25% to be direct billed. As a result, El Paso and Transwestern will recover a maximum of 75% of their take-or-pay costs from their customers.

The SoCal, DRA, and Salmon/Mock proposals can be evaluated by comparing the results that would be produced by their adoption with the results produced under the approach adopted by FERC. If one assumes that SoCal's customers will be paying 50% of El Paso and Transwestern take-or-pay costs through volumetric surcharges and that these costs are passed through to SoCal's customers,[1] then under all three proposals before us, SoCal will recover at least 67% of the take-or-pay costs passed through to California from El Paso and Transwestern to SoCal. SoCal requests full recovery of the remaining direct billed amount which if granted would provide the company with 100% recovery. Salmon/Mock has advocated no recovery beyond the amount included in volumetric charges to SoCal. Under this proposal SoCal would recover 67% of the take-or-pay costs billed to it, but would be required to absorb the remaining 33%. DRA has advocated an alternative approach similar in structure to that adopted by FERC. If one assumes that

1 No party has challenged the volumetric portion of El Paso or Transwestern take-or-pay costs in this proceeding. Only the direct billed portion is at issue.

SoCal elects to absorb the full $1 of direct billed amounts for every $4 billed, then under DRA's proposal, SoCal would recover 80% of direct billed amounts, but SoCal's customers would pay 93% of all take-or-pay costs billed to California. The remaining 7% of all take-or-pay costs billed to California represents the amount SoCal would absorb under these assumptions.

We reject SoCal's request because it is inequitable under the circumstances. It would require all segments of the industry to share the costs of resolving the industry's take-or-pay problems, except SoCal. As a distribution company, SoCal was an integral part of the industry which gave rise to the problem, and as such SoCal should shoulder some portion of the costs of resolving it and moving forward.

For different reasons, we find the proposal of Salmon/Mock to be equally inequitable. In terms of simple percentages, the proposal of Salmon/Mock would require SoCal to absorb a greater percentage of take-or-pay costs than El Paso or Transwestern. Although as a distribution company, we view SoCal as having an important role in ensuring that pipeline purchases are structured so as to ensure marketability of gas to end users, SoCal was not a party to the pipeline-producer contracts which contained the take-or-pay clauses, and has much less control over the negotiations to reduce take-or-pay liabilities than the pipeline companies. For this reason, we conclude that it would be inequitable to adopt a recovery mechanism that is harsher on SoCal that the FERC mechanism is on interstate pipeline companies.

DRA's recommendation is intermediate between these extremes. Assuming SoCal elects to absorb $1 for every $4 direct billed, under DRA's proposal SoCal's customers would pay 93% of take-or-pay costs billed to California, while SoCal's shareholders would absorb 7%. This disparity may appear inequitable to SoCal's customers, but the equities cannot be fairly evaluated without considering the circumstances which gave rise to the take-or-pay liability in more detail. The changes in the industry which permitted the transportation of customer-owned gas significantly reduced customer gas costs. SoCal alleges that its customers saved $1.3 billion as a result of these regulatory changes, and purchases that SoCal made under the new program. Although SoCal received benefits from the changes in regulation including increased recovery of forecast costs included in base rates, and preservation of the company's market share, most of the savings obtained through reduced gas costs directly benefited SoCal's customers. In light of these considerations, we conclude that the DRA recommendation should be adopted. We conclude that it will provide SoCal with a reasonable opportunity to recover take-or-pay costs and strikes a fair balance in allocating risks and costs between ratepayers and SoCal's shareholders.

TURN has recommended that in the event SoCal elects not to absorb any of the take-or-pay costs under the approach we have adopted, there should be no balancing account coverage for the portion of take-or-pay costs allocated to the core market. SoCal has opposed this recommendation on the ground that weather affects sales to the core much more than any other factor and that it would not make sense to permit SoCal to be rewarded if the weather is colder than normal, and penalized if the weather is warm. We agree with SoCal on this point, and will not adopt TURN's recommendation.

In addition, we want to make clear that the decision we have reached is limited to the allocation of costs. We have not considered or determined the reasonableness of any take-or-pay costs SoCal may pass through to ratepayers under this decision. The reasonableness of take-or-pay costs is, as we have stated previously, not an issue in this ACAP case. Any challenge to the reasonableness of take-or-pay costs must be raised in SoCal's annual reasonableness review proceeding.

In order to implement this portion of this decision, within 20 days of the date of issuance of this proposed decision, SoCal shall file comments indicating the rate treatment it selects and proposed rate changes consistent with the company's selection of the ratemaking options provided herein. We also encourage SoCal to include in its comments on this decision any comments it may wish to make on the manner in which the resulting rate changes can best be made.

d. Account 191

El Paso Account 191 direct billed amounts are dependent upon the outcome of settlement negotiations in the El Paso general rate case at the FERC. Settlement negotiations are far from concluded. Both SoCal and this Commission have protested the direct billing of Account 191 undercollections by both El Paso and Transwestern. Because of these uncertainties, both SoCal and DRA recommend that no amount for El Paso or Transwestern undercollections in Account 191 be included in rates in this proceeding.

We agree with the position taken by SoCal and DRA. No undercollections will be forecast in either the El Paso or Transwestern Account 191.

e. Chevron/Southland Refunds

$49.2 million has been received by SoCal from El Paso as a result of the Southland settlement. The Chevron settlement is still on appeal, and as a consequence, SoCal has not received any refund yet from the Chevron settlement. SoCal expects these refunds to eventually total approximately $75 million.

DRA recommends that the Southland refund be held by SoCal as a potential offset to any Account 191 costs that may materialize, and that these amounts be trued-up in SoCal's next ACAP proceeding.

Rather than hold all Chevron/Southland credits for offset against possible future Account 191 direct billings, SoCal proposes to use these refunds to offset direct billed take-or-pay amounts.

TURN is not opposed to using these refunds to offset Account 191 billings, but recommends that the Commission consider the option of a lump sum refund as an alternative.

SoCal's proposal to use Chevron/Southland refunds to offset take-or-pay charges would, in effect, permit SoCal to receive full recovery of any take-or-pay charges offset in this manner. This disposition is inconsistent with our intent to allocate some of the risks and costs associated with the industry's take-or-pay problem to shareholders as well as to ratepayers. Because SoCal may receive substantial direct bills from El Paso and Transwestern during the ACAP period for recovery of Account 191 balances, we will adopt DRA's recommendation. SoCal shall hold Chevron/Southland credits in an interest bearing account for offset against possible future Account 191 direct billings.

f. <u>Mid-la/RFX Refund</u>

SoCal has also received a $36.8 million direct credit with respect to the El Paso "Mid-Louisiana/RFX" proceeding.

DRA recommends that this credit also be held in an interest bearing account for use as an offset against possible Account 191 direct billings. SoCal concurs with this recommendation. TURN is not opposed, but recommends lump sum refund as an alternative. SCUPP/IID contends that the mere potential for Account 191 billings is insufficient justification to permit SoCal to retain these refunds, and opposes the recommendation of SoCal and DRA.

We will adopt DRA's recommendation for the same reason we adopted this treatment of the Chevron/Southland refund.

C. Revenue Requirement

1. Angelus Litigation & Settlement Costs

The Conservation Cost Adjustment (CCA) account is a balancing account which was established by the Commission in D.92854 as part of the demonstration solar financing program. The purpose of the account is to reconcile authorized and expended costs for conservation related programs, and to allow recovery of reasonable conservation program costs.

DRA auditors recommended several adjustments to the CCA account. These related to the Fuel Cell Program, 1986 Tax Reform Act, and litigation and settlement costs related to Angelus, et. al. v. SoCalGas. Prior to the close of hearings SoCal accepted DRA's Fuel Cell adjustment, and the parties agreed to address the effect of the 1986 Tax Reform Act in SoCal's test year 1990 general rate case. Only the Angelus related costs remain at issue in this proceeding.

a. Background

The Angelus litigation arose from the Commission authorized Weatherization Financing and Credits Program (WFCP). The WFCP was established by the Commission in D.82-02-135 (8 CPUC 2d 167) in order to provide 8% financing, or cash credits to residential ratepayers for installation of up to thirteen cost effective weatherization measures.

The Angelus lawsuit was brought by eight contractors who installed residential conservation measures pursuant to SoCal's WFCP program. The contractors alleged various causes of action against SoCal including negligence, misrepresentation, conspiracy to monopolize, and conspiracy to prevent competition. The company incurred approximately $3.86 million in legal fees and associated litigation costs and eventually settled the case by paying the plaintiffs $2.44 million.

b. Positions of Parties

DRA asserts that the CCA balancing account was established to allow SoCal to recover the actual costs of administering the WFCP program, and the costs of the low interest loans and cash credits provided to ratepayers under the program. DRA contends that the potential for litigation arising from conservation programs was recognized by the Commission, but that litigation and settlement costs were never intended by the Commission to receive balancing account treatment or to be recovered through the CCA. In support of this claim, DRA cites language from D.92251, 4 CPUC 2d at p. 312 in which the Commission indicated concern about the potential costs and legal exposure of utilities under the demonstration solar financing program. DRA contends that litigation and settlement costs related to the WFCP programs were intended by the Commission to be recovered, along with all other litigation and settlement costs, on a forecast basis through the allowance for administrative and general expenses included in base rates.

DRA contends that the $6.3 million in settlement and litigation expenses at issue should be removed from the CCA (i.e., the CCA account balance should be revised upward by this amount) and considered part of Accounts 923, "Outside Services", and 925, "Injuries and Damages." Both of these accounts are included within the accounting category of "Administrative and General Expenses" (A&G) which SoCal recovers on a forecast basis through base rates set each of the company's general rate cases. DRA notes that SoCal was authorized $10,811,000 for Account 923 and $6,749,000 for Account 925 in the company's test year 1985 general rate case. Finally, DRA argues that to permit recovery on Angelus related costs through the CCA would give SoCal "double recovery" for these costs. In support of this contention, DRA cites evidence that for a period of at least four years, from 1985 through 1988, SoCal booked conservation related claims expenses to base rate accounts.

DRA infers that SoCal must therefore have included conservation related claims and settlement expenses in the company's A&G forecasts in its last (1985) general rate case.

SoCal responds that the CCA was intended to include all costs related to the WFCP program including any and all litigation and settlement costs, and that the Commission intended to allow recovery of all costs found to have been reasonably incurred. SoCal relies primarily upon D.82-02-135 (1982) 8 CPUC 167, at p. 241 in which the Commission stated that, "In this manner, all expenses and revenues associated with WFPC and RCS will be accounted for in the CCA balancing account." SoCal also cites several Commission decisions related to the Commission's solar financing program in support of its position. In D.92305 (1980) 4 CPUC 2d 396, the Commission indicated that reasonable start up and administrative costs for the solar program should be booked to a balancing account. In D.92854 (1981) (unreported) in A.59869 at mimeo. p. 8, the Commission clearly indicated that overhead burden rates and indirect costs related to the solar demonstration program could be booked to the balancing account. Finally, in D.92251 (1980) 4 CPUC 2d 258 at 312, the Commission indicated its concern that the role of utilities in referring contractors, conducting inspections, enforcing standards, and providing credits or financing under the demonstration solar financing program could give rise to legal exposure to ratepayers as well as to the utility. SoCal concedes that conservation related claims were booked to base rate accounts rather than to the CCA for several years, but alleges that this was an inadvertent error. SoCal further asserts that conservation related litigation and settlement costs were not included in the company's A&G forecast in its last general rate case, and that as a result, permitting recovery through the CCA will not create any double recovery problem.

c. Discussion

Providing balancing account treatment for litigation and claims reduces, if not eliminates, any economic stake utilities have in claims and litigation. There generally are strong policy reasons for ensuring that utilities retain a significant economic stake in litigation. Retaining an economic stake in litigation provides a significant incentive for utilities to minimize claims, litigation, and legal exposure by ensuring that company practices, procedures, and employee conduct conform to laws, regulations, and prudent business practices. It also provides an incentive to evaluate claims, litigation strategies, and settlement options in a realistic manner, and to take a cost effective approach to litigation and settlement negotiations. Balancing account treatment serves none of these policy objectives.

In light of these policy considerations, we are reluctant to infer intent to include WFCP litigation and settlement costs in the CCA balancing account unless there is a clear expression of intent to do so. We find no such evidence of intent.

The Commission authorized that WFCP program expenses be booked to and recovered through the CCA account in D.82-02-135 at p. 239. The program expenses authorized to be recovered through CCA are separately listed under two headings on p. 208 of the decision. The two headings are "Program Incentives," which includes the estimated cost of loans and credits to be provided under the program, and "Marketing, Administration, Etc." which includes administrative and overhead costs authorized to be booked to the CCA. The only subcategories listed under the latter heading are: "Advertising," "Public Affairs," "Marketing & Communications," "Referral Program," "1981 EECP," "Account Administration & Inspections," and "Franchise and Uncollectibles." Litigation and settlement costs are not separately listed, and do not appear to be encompassed in any of the other program categories listed.

Although the Commission did say that all expenses and revenues associated with the WFCP would be accounted for in the CCA balancing account, this statement was prefaced by the phrase "in this manner". We interpret this to mean that the Commission considered the categories and accounts listed on p. 208 of the decision to encompass all of the costs that it considered properly associated with the WFCP program.

Since litigation and settlement costs are not included in the accounts listed, we concluded that these costs were intended by the Commission to continue to be recovered in the unusual manner, i.e., on a forecast basis through the allowance for administrative and general expenses included in base rates. The evidence offered indicates that this conclusion is consistent with SoCal's interpretation of the Commission's intent at the time. This is the most logical inference to be drawn from the fact that the company booked conservation related claims expenses to base rate accounts, rather than to the CCA for four years.

We conclude that the Angelus litigation and settlement costs were improperly booked to the CCA.

2. <u>Oil Revenues</u>

SoCal produces oil in connection with the operation of its Honor Rancho underground gas storage field. Prior to May 1, 1988, Commission decisions required SoCal to credit revenues received for oil production incidental to operation of SoCal's gas storage fields to the Cost Adjustment Mechanism (CAM) balancing account. Through this mechanism oil revenues were used to offset revenue requirement for the benefit of SoCal's ratepayers.

On May 1, 1988 the Commission abolished the CAM procedure and substituted its new program for the regulation of the gas industry. Since May 1, 1988 SoCal has booked oil revenues to the Miscellaneous Revenues account which is a base rate account. Revenues booked to this account do not receive balancing account treatment and are not used to offset revenue requirement, except on a forecast basis in each general rate case. Since oil revenues were subject to balancing account treatment under the CAM procedure at the time of SoCal's last general rate case, they were not taken into account in forecasting the Miscellaneous Revenues account. As a result, of SoCal's accounting treatment of these revenues, since May 1, 1988 ratepayers have been denied the benefit of these revenues, and they have gone directly to benefit the company's shareholders.

The problem applies only to the period from May 1, 1988 to December 31, 1989. SoCal and DRA have agreed to include all prospective oil revenues on a forecast basis in Miscellaneous Revenues (above-the-line) in SoCal's test year 1990 general rate case, A.88-12-047. At issue is approximately $3.0 million.

DRA claims that as a result of accounting workshops held to develop new accounting mechanisms to implement the Commission's restructured regulatory program for the gas industry, it understood that these oil revenues would be booked into the Other Revenue account that is part of the Core and Noncore Fixed Cost Account (GFCA). A detailed accounting stipulation was developed as a result of the workshops DRA mentioned, which was later submitted to and approved by the Commission. The GFCA section of the accounting stipulation requires that revenues subject to balancing account treatment be credited to the GFCA. DRA recommends that SoCal be required to credit the GFCA with the revenues received by SoCal from the sale of oil in the amount of $1.6 million from May 1, 1988 to March 31, 1989, and such actual oil revenues as SoCal will receive between April 1, 1989 and December 31, 1989. According to DRA, this would be consistent with the prior treatment of oil revenues under the former CAM procedure, and consistent with the Commission's intent in establishing the new program.

SoCal contends that since May 1, 1988, there has been no explicit requirement that SoCal reduce customer rates by the amount of oil revenues. SoCal contends that, as a consequence of the absence of any such explicit requirement, the DRA proposal amounts to unlawful retroactive ratemaking. SoCal also claims that DRA's failure to obtain a Commission order requiring crediting of oil revenues against rates after May 1, 1988 does not necessarily create a windfall for SoCal. SoCal argues that oil revenue is only one source of revenue out of the many possible sources of revenue forecasted generally as "miscellaneous revenue" in general rate cases, and there has been no showing that SoCal has received more miscellaneous revenue than it was forecast to receive in the company's last general rate case.

The issue, as we view it, is one of interpretation. We agree with DRA that the accounting stipulation should be interpreted to require that oil revenues, which were formerly subject to balancing account treatment, be credited to the GFCA. To allow SoCal to book oil revenues to the miscellaneous revenue account would result in a direct transfer of revenue from ratepayers and a windfall for SoCal. In implementing our new regulatory program, there was never any intent to change our existing practice of using oil revenues to offset other expenses. They were not included in forecast miscellaneous revenues in SoCal's last general rate case, and we neither intended nor authorized SoCal to book them to this account in implementing the regulatory structure.

SoCal argues that requiring oil revenues to be booked to the GFCA would violate the rule against retroactive ratemaking.

We disagree. SoCal's argument would have merit if the issue did not involve a question of interpretation of our prior intent. Since, however, the issue is a question of how the regulatory changes made last year should be interpreted, and not whether changes should be adopted now and applied retroactively, no retroactive ratemaking problem is involved.

The interpretation we have adopted applies prospectively from the date the regulatory changes at issue were adopted, May 1,

1988. SoCal shall be required to book all oil revenues received between May 1, 1988 and December 31, 1989 to the GFCA.

3. Interutility Transportation Revenue

In addition to PG&E providing interutility transportation service to SoCal over Line 300, SoCal also provides interutility transportation service to PG&E. This service is generally provided to serve EOR customers in localized parts of the San Joaquin Valley where PG&E does not have sufficient facilities and SoCal has available capacity.

DRA forecasts interutility revenue of $1 million whereas SoCal forecasts $0.5 million. The difference is due to two factors: (1) a higher demand forecast by DRA because of new PG&E customer load which DRA indicates will be served through SoCal in early 1989, and (2) SoCal's forecast of curtailment. DRA forecasts demand and throughput of 11,633 Mdth. SoCal forecasts interutility demand of 7,391 Mdth, but only expects to be able to serve 6,150 Mdth.

SoCal does not deny that there will be increased PG&E demand in early 1989, but alleges that this increase will be offset later in the year through the construction of new facilities by PG&E. SoCal has not adequately established when, or the extent to which, this demand will be reduced during the ACAP period through construction of new facilities by PG&E. As a result, we will adopt DRA's interutility demand forecast, but will adopt throughput of 8,700 Mdth that reflects the 2,933 Mdth of curtailment which follows from the system demand and capacity values we have adopted. These adopted values result in an interutility revenue forecast of $0.8 million.

4. Exchange Revenue

DRA forecasts that 29,915 Mdth of exchange gas will be sold by SoCal during the ACAP period bringing $8.685 million in revenue. SoCal forecasts that it will sell 29,566 Mdth which will bring revenues of $8.484 million. The difference is a result of SoCal's forecast of 346 Mdth of curtailment.

We will adopt exchange volume and revenue forecasts of $8.5 million and 29,427 Mdth respectively, which are consistent with the 488 Mdth of curtailment we forecast for this service as a result of our adopted system demand and capacity forecasts.

5. Storage Banking

SoCal estimates that it will receive $1,040,000 in storage banking reservation fees during the ACAP period. DRA agrees with SoCal's forecast. As required by D.89-02-082, this revenue will be credited to reduce the storage related costs allocated to noncore customers.

6. Brokerage Fees

In D.86-12-010, we indicated our intent to remove fixed costs associated with utility brokering activities from core and noncore transmission rates. In D.89-03-014, we reaffirmed our intent to establish brokerage fees for noncore customers and indicated that such costs should be based on embedded costs. We also ordered PG&E and SoCal to include appropriate cost information in their next ACAP proceedings in order to implement such fees. In PG&E's recent ACAP, we addressed this issue in further detail, and adopted general guidelines for determining appropriate brokerage fees. We indicated that brokerage fees should include all costs associated with brokerage type services, including marketing costs.

> "(B)rokerage cost estimates should include (1) the costs of developing and maintaining gas supply and customer information; (2) communications costs; (3) computing, accounting and billing systems costs; (4) associated legal and regulatory expenses; (5) the costs of letters of credit and uncollectibles; (6) working capital for inventory gas, gas temporarily unaccounted for, and gas purchased but not paid for by the customer; and (7) lost and unaccounted for gas. ...(E)stimates of brokerage costs should include not only operating costs, but capital costs as well, to the extent capital

> investments are required for procurement operations." (D.89-09-094 at pp. 10-11.)

We further stated that absent a compelling showing to the contrary, we would consider these guidelines to reflect methodology to be applied in future ACAP proceedings.

SoCal submitted testimony to quantify its brokerage related costs and estimated brokerage costs in the amount of $1,494,000. This estimate was developed from 1983 cost data and includes only procurement related costs. SoCal contends that it incurs no marketing related costs on account of gas brokering.

DRA, Salmon/Mock, TURN, and SCE all disagree with SoCal's estimate.

DRA contends that SoCal has excluded marketing related costs contrary to clear Commission policy, and has used outdated data for estimating procurement related costs. DRA contends that using 1983 data cannot possibly capture costs now incurred due to the many changes in the industry that have occurred since then. Because of changes made in SoCal's organizational structure and accounting procedures, DRA was not able to update SoCal's cost estimate to correct for these deficiencies. DRA recommends that an interim brokerage fee be established based upon the best available data, and that SoCal be ordered to perform a complete study of marketing and procurement costs using current information. DRA reviewed data filed by SoCal in the company's 1990 general rate case to develop an estimate of brokerage costs, that includes both procurement and marketing related costs, that can be used on an interim basis. Based upon this data, DRA estimates brokerage costs of $3,878,000, which includes $2,378,000 for procurement related costs, and $1,500,000 for marketing related costs.

Salmon/Mock also contends that SoCal's cost estimate is both incomplete and based upon outdated information. Salmon/Mock agrees with DRA that SoCal should be ordered to conduct a detailed new study to quantify all embedded brokerage related costs as defined by the Commission in D.89-09-094, and recommends that this study be considered in SoCal's next ACAP. Salmon/Mock has attempted to quantify SoCal's brokerage related costs and recommends that an interim brokerage fee be adopted on this basis pending completion of a new study by SoCal. Salmon/Mock estimates SoCal's brokerage costs at $5.2 million, and recommends that the revenue be allocated to reduce noncore transmission rates.

TURN agrees that SoCal's brokerage cost estimate is incomplete and joins other parties in advocating that SoCal be required to prepare a new cost study consistent with Commission policies. TURN agrees with DRA and Salmon/Mock that an interim brokerage fee should be adopted in this proceeding, and supports the cost estimate developed by Salmon/Mock. TURN suggests that the ratio implicit in DRA's recommendation (61% procurement and 39% marketing) be utilized in allocating the costs. TURN adovocates that the procurement portion be allocated (subtracted from) noncore transportation rates. TURN recommends treating the marketing portion as customer-related costs, and recommends that we apply the same allocation between core and noncore as we have applied to customer-related costs. Under this approach, 98.133% of the marketing related costs would be applied to reduce core rates, and 1.867% to reduce noncore transportation rates. DRA supports TURN's recommended allocation of brokerage costs.

SCE agrees with the recommendation that SoCal be required to develop a new cost study that includes marketing costs, but objects to the recommendation that an interim brokerage fee be established pending completion of the new study. SCE contends that no brokerage fee should be implemented until an adequate cost study has been completed.

We agree with DRA, Salmon/Mock, TURN, and SCE that SoCal's estimate of brokerage costs is based upon outdated costs information, and is clearly incomplete. As a result, we will order SoCal to prepare a new cost study of brokerage related costs, consistent with the guidelines contained in D.89-09-094, for consideration in SoCal's next ACAP.

We also agree with DRA, Salmon/Mock, and TURN that an interim brokerage fee should be established pending consideration of the new cost study we have ordered SoCal to develop. In the interim, we will set a brokerage fee based upon the costs estimated by DRA. Although it is not entirely clear whether DRA has captured all costs included in the guidelines specified in D.89-09-094, DRA's overall estimate appears reasonable in light of the record on this issue. We accept the breakdown between procurement and marketing related costs implicit in DRA's cost estimate for cost allocation purposes, and will adopt TURN's recommended basis for allocating the marketing portion between core and noncore customers.

7. Cogeneration Shortfall Account

The Cogeneration Shortfall Account (CSA) was established for the purpose of tracking the difference between the monthly average UEG rate and the otherwise applicable commercial or industrial cogeneration rate. Anytime the otherwise applicable rate is less than the UEG rate, the resulting "shortfall" may be booked to this account. (See D.88-03-041 at mimeo. pp. 18-19.)

SoCal has recorded $14.4 million in "shortfalls" in its CSA and requests that the balance be amortized in rates in this proceeding. SDG&E and PG&E support SoCal's request.

DRA, TURN, SCE, SCUPP/IID, CCC, and CSC oppose SoCal's request on the basis that the recorded "shortfall" is an artifice of the way the account was setup, and does not really represent any actual revenue shortfall. They contend that the Commission did not consider the effects of UEG curtailment or fuel switching when the account was established, and that the recorded "shortfall" reflects nothing more than increases in the monthly average UEG rate as a result of fuel switching and curtailment. They contend that under these circumstances, the recorded "shortfall" really represents a potential windfall for SoCal--a windfall that will be realized if the Commission allows the company to recover the balance in the account. In support of this argument, they offered evidence that the actual contribution of cogenerators to non-procurement costs was higher, not lower, than projected.

Furthermore, because the account has not functioned as originally intended, and will not function as intended under any reasonably forseeable set of circumstances, TURN, SCE, SCUPP/IID, and CSC advocate that the account be abolished altogether.

SoCal argues that the Commission considered and rejected proposals to abolish the account in PG&E's recent ACAP. The company does not, however, oppose abolishment of the account if the company's proposal to base cogeneration rates on forecast UEG throughput is adopted.

We agree with TURN, DRA, and others that the balance in the account is primarily a consequence of unexpected dramatic increases in the recorded average monthly UEG rate which resulted from UEG fuel switching and curtailments. When UEG curtailment or fuel switching occurs, the average monthly UEG rate increases dramatically because there is much less volume over which to spread the fixed monthly costs allocated to UEG customers. When this occurs, the monthly average UEG rate increases well above the otherwise applicable commercial or industrial cogeneration rate, and the difference between these rates is reflected as a "shortfall" in the CSA. This can and does result even though actual revenues received by SoCal are at or above forecast levels. As a result of these effects, the present account balance does not reflect any real revenue shortfall. We agree that allowing SoCal to recover the CSA, balance under these circumstances, would provide the company with a windfall. Accordingly, we will not allow SoCal to amortize the balance in the CSA.

We have addressed SoCal's claim that it is entitled to recover expenses authorized by the Commission to be booked to tracking accounts earlier in this decision. As previously indicated, authorizing costs to be booked to a tracking account is no guarantee of future recovery. The Commission may authorize such treatment for the purpose of permitting further review of the costs recorded in such an account, and that is precisely the purpose for which the CSA was authorized.

We also agree with TURN, SCE, SCUPP/IID, and CSC that the account should be abolished. It has not worked as intended, and is not likely to work as intended under any reasonably foreseeable set of circumstances. For these reasons, we will abolish the account.

8. **Company Use and Lost and <u>Unaccounted for Gas</u>**

DRA recommends that revenue requirement associated with company use and Lost and Unaccounted for (LUAF) gas be proportionally reduced if forecast throughput is reduced due to curtailments.

We agree. Revenue requirement associated with company use and LUAF gas will reflect the effects of forecast curtailments on throughput.

D. <u>Cost Allocation</u>

1. **Public Utilities Code <u>§ 739.6 Restrictions</u>**

Public Utilities (PU) Code § 739.6 limits Commission discretion to modify its existing methodology for allocating gas company costs among the various customer classes. The statute states, in part:

> ". . . The cost allocation methodology adopted for gas corporations by the commission in Decisions 86-12-009 and 86-12-020, 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. . . ."
> (PU Code § 739.6.)

In our opinion, it is the clear intent of the statute to maintain the Commission's existing cost allocation practices, at least until January 1991. The Commission is, however, extended latitude to modify existing practices in limited circumstances. The conditions under which a change can be considered are limited to situations of customer hardship or inequity. Even where these conditions are met, the statute prohibits cost allocation changes unless the hardship or inequity can be eliminated without, on balance, adversely affecting residential ratepayers.

Given the express limitations of the statute and its clear intent, we will not entertain modifications to our existing cost allocation practices unless a clear and compelling case of customer hardship or inequity is demonstrated. We have established this high threshold for considering modifications not only because of the clear intent of the statute, but also because the statute restricts our ability to provide comprehensive solutions to cost allocation problems. The only remedies that can be considered under the statute are those which "on balance" do not adversely affect residential ratepayers. As a result, the customer classes to which we may spread costs in order to remedy hardships and inequities are limited, and there is a very real possibility that in remedying one perceived inequity, we may create or aggravate another. As a result of these concerns, we are reluctant to change our existing cost allocation practices in any significant respect until we have the discretion to consider cost allocation in a comprehensive fashion. We will maintain existing cost allocation policies, unless we find a compelling reason for change that can be made consistent with the requirements of the statute.

2. Long-Term Contracts

SoCal has negotiated and signed long-term service contracts with both SDG&E and SCE. If approved, these contracts will affect the allocation of costs in this proceeding in a number of respects. SoCal's request for approval of these contracts is under consideration by the Commission in C.89-05-016 and a decision is currently pending. The assigned ALJ has recommended that the Commission disapprove the contracts. As a result of this recommendation, we have assumed, for purposes of this ACAP decision, that the proposed decision will be adopted by the Commission.

3. Purchased Gas Adjustment Over and Undercollections

The Purchased Gas Adjustment (PGA) is a balancing account which reflects past period under or overcollections of core portfolio gas. SoCal proposes to allocate the PGA balance to core customers only. DRA recommends that it should be allocated to all users of the core portfolio including core-elect customers.

We agree with DRA and will allocate the PGA balance to core and core-elect customers.

4. EOR Overcollections

DRA and SoCal independently identified a $33.5 million allocation error in the allocation of the EOR revenue credit in the company's April 12, 1989 filing. Both DRA and SoCal agree that the credit should be allocated to all customers, rather than to noncore only, but they disagree about the basis to use for the reallocation.

DRA recommends allocating EOR revenue credits on the basis of the prospective forecasts developed in this ACAP period. SoCal and SDG&E recommend that they be allocated on the basis of prior period group revenue forecasts.

We agree with DRA. Allocating over and undercollections on the basis of current forecasts is more convenient from an administrative standpoint, and provides a better basis for developing equitable rates than using prior period forecasts. For these reasons DRA's recommendation to allocate the EOR overcollection on a forecast basis, on an equal percentage of "fixed cost" revenues (base plus pipeline demand) will be adopted.

5. Cogeneration-UEG Rate Parity Subsidy

SoCal has proposed that the difference between the revenues cogenerators will pay (paying the average UEG rate) and the higher cost of serving cogeneration customers be spread to the UEG and cogeneration classes. This is consistent with prior Commission decisions.

SCUPP/IID and SCE have proposed that this cogeneration subsidy be spread to all customer classes rather than just to the UEG/cogeneration classes.

In D.87-05-046, we decided that the difference in the revenues generated by cogeneration customers and the cost of providing service to this class should be allocated to the combined UEG/cogeneration classes because these are the classes responsible for the shortfall. We are not persuaded that any change in this policy is warranted. We will spread the revenue deficiency to the UEG/cogeneration classes.

6. Allocation of Take-or-Pay Costs

SoCal has proposed that take-or-pay costs be recovered from all customers. SCE agrees that SoCal should be permitted to recover all reasonably incurred take-or-pay costs, but argues that the portion of such costs allocated to UEG customers should be reduced to 25% of what would otherwise be allocated to UEG customers using a standard equal cents per therm allocation. SCE claims that this reduction in allocation is warranted because SCE took gas during the mid- to late 1970s and thereby incurred significant take-or-pay costs of its own under oil contracts the company had entered into.

We are not persuaded. In our opinion, the equities involved in this issue are far more complicated than SCE represents. While SCE did take gas and thereby incur its own take-or-pay liabilities under oil contracts negotiated during this period, SCE has already recovered all reasonably incurred take-or-pay costs from its ratepayers. Moreover, to some unquantified but arguably significant degree, SCE benefited directly from the regulatory changes and lower gas prices made possible by these changes. Lower gas prices during this period increased sales potential and the potential recovery of forecast revenues. The take-or-pay costs now at issue have arisen as a result of dramatic market and regulatory changes in the gas industry for which, as FERC has observed, all segments of the industry bear some responsibility. Moreover, the Commission has already decided that, to the extent transition costs are recovered, they should be recovered from all customers, including UEG.

7. Allocation of Costs to Wholesale Customers

A variety of issues were raised, primarily by SDG&E and Long Beach, concerning the allocation of costs to SoCal's wholesale customers. These are addressed in the sections which follow. Issues related to the allocation of fixed costs between SoCal and SDG&E are material to this proceeding only if the SDG&E-SoCal long-term contract is disapproved by the Commission. For purposes of this decision, we have assumed that the contract will be denied since the ALJ in C.89-05-016 has recommended this disposition.

a. Lost and Unaccounted for Gas

SoCal filed cost studies on LUAF and administrative and general expenses (A&G) together with its application in this proceeding. These studies were filed to comply with earlier

Commission directives, but the company does not propose to allocate either cost in this proceeding on the basis of the studies. SoCal contends that these studies may require changes which would violate the provisions of PU Code § 739.6, and proposes to allocate LUAF and A&G costs to all customers in accordance with prior Commission decisions pending future review of these studies.

TURN moved to exclude the studies, and all testimony related to the issues raised by the studies, on grounds that the implementation of the studies would violate PU Code § 739.6. The motion was denied by the ALJ on grounds that the statute contains an exception for hardships and inequities, and that the parties should at least be permitted to file testimony to make a prima facie case that the requirements of the statute could be met. In view of the number and complexity of issues raised in this proceeding, the ALJ also decided that the hearing time available in this phase of the proceeding was clearly inadequate to fully evaluate the validity and implementation of SoCal's LUAF and A&G cost studies. As a consequence, the ALJ ruled that consideration of these studies would be deferred to a subsequent phase of this ACAP. We concur with an affirm this ruling.

We concur with the ALJ's rulings on this issue, but want to emphasize that we interpret the statute to have established a high threshold that must be met in order to justify any change in our existing cost allocation procedures.

Following this ruling, Long Beach, SDG&E, DRA, and TURN entered into a stipulation which, if implemented, would relieve SoCal's wholesale customers from responsibility for SoCal's LUAF gas costs on an interim basis pending review of SoCal's LUAF study. The stipulation states that the allocation of LUAF costs to SDG&E and Long Beach constitutes an inequity and causes hardship. It attempts to meet the requirements of PU Code § 739.6 by requiring that any increased costs to SoCal's residential ratepayers be offset by reductions in costs allocated to the residential customers of Long Beach and SDG&E.

SoCal, SCE, and TURN oppose implementation of the LUAF study this time.

SoCal argues that partial implementation of these studies is ill advised. In support of this position, the company points out that partial implementation of the studies for the benefit of wholesale customers would increase the LUAF costs which must be allocated to SoCal's retail noncore customers even though the LUAF study supports a reduction in the allocation to these customers.

TURN raises concerns about the accuracy of both the SoCal A&G and LUAF studies. TURN also opposes consideration of the A&G and LUAF studies in a subsequent phase of this case on grounds that the results of the study could not be implemented in a manner consistent with the intent of PU Code § 739.6.

SCE opposes consideration of the studies until their validity has been considered by the Commission. SCE supports consideration in a subsequent phase of this proceeding.

SCUPP/IID are also opposed to the implementation of the LUAF study, but for a different reason. SCUPP/IID argues that if the relief requested by Long Beach and SDG&E is granted, it should be granted not on the basis of the fact that they are wholesale customers, but rather on the basis of the fact that they are served at the transmission rather than distribution level. SCUPP/IID further argues that on this basis, the same relief that Long Beach and SDG&E seek should also be extended to SoCal's retail UEG customers.

TURN has raised legitimate concerns about the accuracy of the SoCal studies. The Commission is not inclined to make interim rate changes on the basis of cost studies prior to determining their validity, unless the changes are beyond dispute. In this instance, the need to reduce the allocation of costs to wholesale customers appears clear, but this conclusion still depends upon the validity of the SoCal study. And, even if this general conclusion is valid, the amount of the reduction that may be warranted can not be determined until the accuracy of the study is determined. Of equal concern is the fact that wholesale rates could not be reduced, consistent with PU Code § 739.6, without increasing other nonresidential rates to potentially unjustified levels. This issue requires further consideration. Because of these concerns, we are persuaded that the implementation of SoCal's A&G and LUAF studies should be deferred until their validity has been determined, and until we are confident that an equitable allocation of costs can be made to all customer classes. Accordingly, we will not adopt the Long Beach stipulation.

b. Long-Term Contract Shortfalls

DRA, Long Beach, and SDG&E recommend that the cost of SoCal's long-term contract shortfalls not be allocated to SDG&E or Long Beach. They assert that because Long Beach and SDG&E operate their own retail systems, they may have to negotiate special discounted long-term contracts to preserve load on their systems, just like SoCal negotiates to preserve load on its system. They argue that it would be inequitable to allocate SoCal's long-term contract shortfall to wholesale customers when wholesale customers have no ability to reciprocate by allocating a portion of their shortfalls back to SoCal.

SoCal, SCE, and SCUPP/IID oppose this request on the grounds that the company's long-term contracts provide additional revenue that benefits all of SoCal's customers, including wholesale customers, and that the Commission has already decided, in D.87-05-046 that revenue shortfalls from existing long-term contracts should be allocated to all customers. SoCal argues, in addition, that there isn't really any shortfall created by these special discounted long-term contracts because they contribute additional revenue to cover SoCal's fixed costs which would not be available if these customers reduced their purchases from SoCal, or left SoCal's system. The shortfall is nothing more than additional revenue requirement that would have been obtained, if it had been possible to maintain the same level of sales without discounting.

We agree with SoCal that long-term contracts should provide additional revenue to offset fixed costs. On this basis, we have previously allocated revenue shortfalls from such contracts to all customers. We are not persuaded, however, that the issue raised by DRA, Long Beach, and SDG&E should be resolved solely on this basis. Equitable problems are presented by the application of the principle to wholesale customers. We agree that long-term contracts Long Beach and SDG&E may negotiate can have the same beneficial effects for SoCal that SoCal's own long-term contracts have. In light of this, one could legitimately argue, as DRA, Long Beach and SDG&E have, that it is inequitable to allocate a portion of SoCal's contract shortfalls to wholesale customers when there is no provision for allocating the long-term contract shortfalls of wholesale customers back to SoCal. Even though we agree with these arguments of DRA, Long Beach, and SDG&E, we are not persuaded that a change in our current cost allocation policy concerning long-term contracts is warranted at this time. All of the arguments offered by DRA, Long Beach, and SDG&E are theoretical. There has been no evidence offered concerning the long-term contracts that SDG&E and Long Beach may have signed, or the amount of any revenue shortfalls experienced by SDG&E or Long Beach as a result of such contracts. Absent such evidence, we cannot conclude that any real hardship or inequity within the meaning of PU Code § 739.6 has been shown. Until such a showing is made, we will continue to allocate a portion of SoCal's long-term contract shortfall to wholesale customers.

c. <u>Company Use Gas</u>

Company use gas is currently allocated to customers on the basis of forecasted throughput. SDG&E alleges that this cost allocation methodology results in the allocation of more of SoCal's company use gas costs to SDG&E than is warranted. SDG&E proposes that SoCal's company use gas be allocated instead on the basis of the percent of total margin expenses allocated to SDG&E.

SoCal opposes SDG&E's proposal on grounds that the vast majority of company use gas is related to throughput and should therefore be allocated on the basis of throughput to each customer class. SoCal alleges that approximately 68% of company use gas is incurred for transmission of gas, and an additional significant amount for gas storage operations.

We agree with SoCal. SDG&E's proposal would effectively reduce the wholesale customers' share of company use gas from 13% to 3% of total company use cost, and the company has failed to present any convincing reason for such a change in our cost allocation policies.

d. Carrying Cost of Gas Storage

SDG&E and Long Beach contend that they should not be allocated a portion of SoCal's carrying cost of gas in storage. In essence, they argue that they store their own gas, and that to require them to pay a portion of SoCal's carrying cost of gas in storage would result in their customers being charged twice for this cost.

SoCal concedes, as it must, that to the extent that SoCal is actually relieved of some carrying costs by requiring less of its own gas in storage, then the argument of the wholesale customers makes sense. SoCal argues, however, that wholesale customers should not be relieved of all carrying costs because these customers still have the right to elect core procurement service from SoCal and as a result, SoCal cannot ignore the potential for such an election.

We conclude that wholesale customers should be excused from some, but not all carrying costs of gas in storage. To the extent wholesale customers elect core procurement service, storage related costs are directly incurred for their benefit. Storage costs are also incurred for the indirect benefit of customers purchasing gas from SoCal's noncore portfolio because it is storage of core gas that permits noncore service to continue during periods of peak demand. Moreover, the right of wholesale customers to elect core procurement service compels SoCal to adopt storage goals and strategies that take the potential for such election into account. As a consequence of these factors, storage related costs are incurred for the benefit of wholesale customers whether or not they avail themselves of the core elect option. To the extent that wholesale customers store their own gas they incur carrying costs themselves, and SoCal is relieved of some storage costs that would otherwise be incurred by the company for the benefit of wholesale customers.

In light of all of these considerations, we conclude that wholesale customers should be given a credit based upon the amount of gas they actually store on their own account during the ACAP period. We conclude that it would be inequitable within the meaning of PU Code § 739.6 to allocate the carrying cost of gas to wholesale customers under these circumstances, and conclude that this inequity can be remedied without adversely affecting residential ratepayers.

We will allocate storage costs to wholesale customers in this proceeding on the basis of forecast throughput. Each wholesale customer shall, however, be entitled to claim a credit against the storage costs allocated to it, equal to the carrying cost of gas stored by the wholesale customer during the ACAP period. This credit may be claimed in SoCal's next ACAP proceeding, and will be used to offset costs allocated to wholesale customers in that proceeding provided that residential customers are not, on balance, adversely affected.

e. Allocation of SoCal Transmission Facilities to SDG&E

SDG&E has proposed to change the existing allocation of SoCal's Moreno to Rainbow transmision lines 1027 and 1028, and the Orange County portion of Line 1026. SDG&E proposes that the cost of these lines be treated as demand related transmission costs, and allocated to all customer classes in the same manner at SoCal's general transmission system, i.e., on the basis of cold year annual throughput. SDG&E accepts full cost responsibility for facilities which are devoted 100% to serving SDG&E, such as the Dana Point Compressor Station and Line 1026 San Diego County, but argues that Moreno to Rainbow and the Orange County portion of Line 1026 should be treated differently because these lines serve other customers in addition to SDG&E. SDG&E argues that its proposal is consistent with PU Code §739.6 because the increase to SoCal's residential ratepayers will be offset by a decrease to SDG&E's residential ratepayers.

SoCal opposes the proposal of SDG&E on the grounds that these facilities are used primarily to serve a single large customer, SDG&E, and that under these circumstances, it is appropriate to make a direct assignment of costs. SoCal also argues that SDG&E requested and was granted such a direct assignment in D.87-05-046. SoCal also notes that SDG&E's proposal would reduce the amount allocated to SDG&E from a majority to approximately 10% of the costs of these lines.

DRA supports SDG&E's proposal even though the lines in question are used "almost exclusively" to serve SDG&E. DRA draws a distinction between lines dedicated 100% to serving a particular customer, and lines which are not exclusively devoted to a single customer. The former, DRA feels should be allocated to the customer to whom the facilities are dedicated. The latter DRA asserts should not be allocated in any different manner than other transmission lines which are allocated to all customers. DRA argues that lines devoted mostly to serving a customer cannot be allocated in a separate manner without also allocating in a separate manner many other facilities which are located far from the customer and are used little, if at all, to service the customer.

Although we find theoretical merit to the arguments of SDG&E and DRA, we are not persuaded that this change should be adopted at this time. There has been no real showing that the present method has resulted in hardship or is inequitable, and as a result, we are not persuaded that the requirements of PU Code § 739.6 have been met. SoCal's proposed methodology is closer to the method previously used to allocate the cost of these facilities and will be adopted.

f. Allocation of Balancing Accounts from SoCal to SDG&E

SDG&E proposes to change the manner in which various balancing account balances are allocated from SoCal to SDG&E in order to remedy what SDG&E contends is an inconsistency between SoCal's core and noncore balancing accounts and SDG&E's core and noncore balancing account balances. SDG&E believes that the reason for these differences is that SoCal allocates balancing account balances to SDG&E as though it were one noncore customer. SDG&E proposes to remedy this perceived problem by, in effect, treating SDG&E as two separate customers, a core customer representing all of SDG&E's core load, and a noncore customer representing all of SDG&E's noncore load. This would change the allocation of a number of balancing account balances, and result in a net decrease in the allocation to SDG&E of approximately $0.6 million.

SoCal opposes SDG&E's proposal on several grounds, including: (1) that it is inconsistent with prior Commission decisions which indicate our intent to treat wholesale core and noncore load in the same manner, (2) that all of SDG&E's throughput was used in allocating costs to SDG&E as a single customer in D.87-12-039 and that as a result, true-up of differences between forecast and recorded costs should be done on the same basis, (3) inconsistencies in the way SDG&E records its account balances should not control the amount of SoCal's costs that should be allocated to SDG&E, and (4) that the Commission has indicated its intent to amortize account balances for entire classes on the basis of forecast throughput, not recorded individual customer group throughput.

We agree with SoCal. In D.86-12-009 at p. 59, we stated that wholesale customer core and noncore load would be treated as a single entity for rate setting purposes, and we are not persuaded that the perceived inconsistencies cited by SDG&E warrant the kind of remedy SDG&E advocates.

g. Allocation of PITCO and POPCO Demand Charges

Long Beach argues that it should be allocated no PITCO or POPCO demand charges because it allegedly requested and was refused transportation service from those companies.[2]

In D.86-12-009 at p. 32, the Commission decided that interstate pipeline fixed charges should be allocated to all customers on the basis of cold year annual throughput. This allocation was based upon the conclusion that cold year throughput best matches the costs of interstate pipeline capacity with the customers that benefit from the availability of this capacity. To the extent that service to Long Beach can be provided under cold

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2 Long Beach introduced no evidence in substantiation of this representation, and although no party explicitly disputed it, SoCal did object to Long Beach raising this argument without having first established, by record evidence, the factual foundation upon which it is based.

year conditions, Long Beach benefits, regardless of the source or sources from which that capacity is available, and regardless of whether or not transportation service was denied Long Beach by a particular pipeline. Accordingly, we will not alter our existing method of allocating PITCO and POPCO demand charges.

h. Allocation of Franchise Fees to Long Beach

Long Beach argues that it should not be allocated any portion of SoCal's franchise fees because the Long Beach Gas Department pays amounts in lieu of franchise fees to the City of Long Beach. As a result of these payments, Long Beach contends that it would be inequitable to require its ratepayers to pay a portion of SoCal's franchise fee payments in addition to what they already implicitly contribute to the City of Long Beach.

SoCal objects to consideration of this issue at this time because Long Beach failed to raise the issue in hearings, and thereby deprived SoCal of the opportunity to introduce evidence of "the very substantial franchise fees that SoCal Gas pays to the City of Long Beach."

While we are not persuaded by Long Beach's argument, the issue raised is not one that can be resolved solely on the basis of the argument of counsel. It appears to require testimony on factual matters in dispute. The service SoCal provides to Long Beach, just like the service SoCal provides to its other customers, cannot be provided without the use of facilities located in public streets and rights of way spread throughout SoCal's service territory. As a consequence, at least some portion of the franchise fees SoCal pays to cities and counties throughout its service territory are incurred for the benefit of Long Beach. In our opinion, it is immaterial how these franchise fee payments are computed, it is the purpose for which they are incurred that is important for allocation purposes.

If Long Beach desires to raise this issue in a future proceeding, it must do so in a manner which provides SoCal with a reasonable opportunity to introduce evidence concerning costs incurred for the benefit of Long Beach. We will defer resolution of this issue to a subsequent proceeding in which SoCal is provided notice and an opportunity to introduce evidence in rebuttal to Long Beach.

E. Rate Design

1. Residential

a. Customer Charge

SoCal proposes to increase the customer charge for residential service from $3.10 per month to $5 per month. SoCal claims that the actual fixed costs of residential service are approximately $10.18 per month, and that its proposed increase is consistent with the Commission's policy of bringing rates more closely in alignment with the actual costs incurred in providing service. DRA agrees that the fixed costs of providing residential service justify an increase in the customer charge, but proposes a more modest increase to $3.75 per month. TURN opposes any increase in the customer charge on the ground that this change in rate design will encourage greater residential consumption. TURN questions what public policy objective would be served by such action.

We have considered the arguments made in support of proposals to increase the monthly customer charge, and are not persuaded that an increase is warranted at this time.

The policy of designing specific rates to recover the costs of providing specific types of services, must be considered in light of the objectives sought to be accomplished by its application. Where competitive market forces exist, this policy may be justified on grounds of increasing the efficiency of the market and thereby, in theory, promoting overall cost minimization. In the context of residential gas rates, however, competitive factors are severely restricted. Utilities still enjoy a monopoly in this market. Any perceived economic benefits of increasing residential customer charges must be considered in light of the limited competition in this market, and must be weighed against other policy objectives involved. Among the other policy objectives that should be considered in this context are: (1) maintaining or increasing customer control over monthly utility bills through usage sensitive rate design, (2) maintaining an appropriate balance of risk between ratepayers and utilities under our new gas program, and (3) maintaining residential conservation incentives. Other things being equal, these objectives are better accomplished either by maintaining the present allocation of costs between customer and volumetric charges, or by assigning fewer costs to the customer charge, and more costs to volumetric charges.

We conclude that, in the residential context, these other policy objectives outweigh any benefits that might be achieved by increasing the customer charge to more closely match the fixed costs of providing residential service. Accordingly, we will maintain SoCal's customer charge at the existing $3.10/month level.

b. Baseline Allowances

PU Code § 739(d) requires that baseline quantities be established at from 60% to 70% of average residential consumption during the winter heating season. In D.87-12-039, we adopted a phased reduction in baseline allowances in order to bring SoCal's rate structure into compliance with this statutory mandate within three years. The purpose of this phased approach was to minimize rate shock to residential customers. In order to accomplish this objective, we indicated that SoCal could increase residential rates, due to baseline implementation, not more than 15% above the class average.

DRA, TURN, and SoCal all agree that a reduction in SoCal's baseline allowances is required, but differ in the amount of the reduction which they recommend.

SoCal proposes to reduce baseline allowances from their present levels of 62, 81, and 108 therms to 50, 65, and 87 therms per month for Climate Zones 1, 2, and 3, respectively. These changes would bring SoCal's winter baseline allowances into compliance with the statute.

DRA recommends that we continue the phase-in of new baseline quantitites in order to minimize rate shock, and states that any reduction should be kept within the maximum authorized under the guidelines adopted by the Commission in D.87-12-039. DRA did not recommend a specific reduction because it felt that the impact of any reduction could not be evaluated until the proposed rates as a result of this decision are made available.

TURN contends that the proposal of SoCal exceeds the guidelines established by the Commission for the phase-in of baseline reductions. TURN argues that the effect of SoCal's proposal is in excess of the 15% standard if the company's proposed baseline reductions are considered along with the company's proposed increase in the residential customer charge. TURN proposes winter baseline quantities of 55, 72, and 96 therms for Climate Zones 1, 2, and 3, respectively.

We share the concerns expressed by DRA and TURN about the effects of rate design changes on residential customers' bills. As a result, we will reduce baseline allowances consistent with our previously adopted three-phase program.

c. Differential Between <u>Tier I and Tier II Rates</u>

Increased residential gas consumption during the winter season and the large differential that has existed between residential Tier I and Tier II rates has resulted in wide swings in many customers' gas bills between the summer and winter seasons, and dramatic increases in winter bills. As a result, both this Commission and the Legislature have taken action to modify rate design structures to reduce high nonbaseline residential rates.

Senate Bill 987, now codified as PU Code § 739.7, directs Commission to address this recurring problem.

SoCal, DRA, and TURN all agree that the differential between Tiers I and II should be reduced, but differ in the manner in which this should be accomplished.

SoCal proposes using the additional revenue obtained through the company's proposed increase in the residential customer charge to reduce the Tier II residential rate. This would significantly reduce the difference between Tier I and Tier II rates.

DRA believes that the differential between tiers should be reduced "to the extent allowed by rate impacts", and proposes decreasing the differential by applying any increase to Tier I rates.

TURN expressed general opposition to raising residential rates in the context of a rate case which requires an overall rate decrease, but proposed that the baseline rate be increased first, by up to 5%, and that any increase required beyond that point be allocated to both tiers on an equal cents per therm basis. This approach, TURN argues would moderate the current tier differentials without causing major customer impacts.

We agree that customer impacts must be considered in reducing the differential between tiers. Proposals which change only one of the two tiers would impact some customers in a manner quite disproportionate to the overall residential rate change. Allocating all of the residential increase to Tier I would, for example, greatly exaggerate the impact on low-usage customers. We agree with DRA and TURN that these impacts should be moderated, while still moving rapidly to reduce the differential. Consequently, we will increase both Tier I and reduce Tier II.

2. Commercial/Industrial

a. Proposal to Combine P2b and other Industrial

SoCal has proposed combining its "P2B" and "Other Industrial" rate schedules. In support of the proposed change, SoCal states that the rates for these classes are essentially the same, and they wish to combine them for administrative convenience. DRA is opposed to this change.

Although the rates for SoCal's P2B and Other Industrial classes are at present quite close, they may not always be so. The differences in these classes reflect not only differences in end use priority, but also different alternate fuel capability. We conclude that the differences in these classes continue to warrant separate rate schedules.

b. Commercial/Industrial Demand Charge

SoCal proposes to retain the same demand and volumetric rate structure as is presently in effect for commercial and industrial customers. CIG/CLFP recommends that this rate structure be fundamentally changed by eliminating the demand charge, and substituting an all volumetric rate design. DRA joins SoCal in opposition to CIG/CLFP's proposal.

We have considered the arguments made by CIG/CLFP and are not persuaded that a change is warranted at this time. The structure of our present commercial and industrial rate design is an integral part of the balancing of risks which we undertook in establishing the new regulatory program for the gas industry. The program is still quite new, and as a result, we are reluctant to make changes which would significantly alter the balance of risk without a compelling reason to do so. The proposal of CIG/CLFP would increase risk to SoCal, and would relieve commercial and industrial customers that fuel switch of cost responsibility for fixed costs associated with facilities SoCal maintains for their benefit when they choose to use gas. Moreover, noncore customers that have special problems as a result of the demand charges included in our default rate structure are free to negotiate special contracts with SoCal to address their particular problems. We find no compelling reason to modify the existing rate structure for commercial and industrial customers.

c. Definition of Winter/Summer Seasons for Core Non-Residential

DRA proposes to change the definition of the winter and summer seasons for application to seasonally differentiated rates to core non-residential customers from the present 6 month/6 month periods to a 4-month winter and 8-month summer split. SoCal opposes this proposed change on grounds that it could contribute to high winter bills for temperature sensitive core customers during cold spells.

DRA's proposed seasonal definitions are the same currently used for developing seasonally differentiated noncore rates and would allow rates to be designed that more closely match the incurrence of cost to meet peak winter demand.

3. Cogeneration

a. Proposal to Use Forecast Basis

Currently, the average cogeneration transportation rate is based on the recorded average UEG gas rate filed monthly, lagged by two months. This rate setting approach occasionally produces wide variations in the cogeneration rate. When UEG gas throughput is low, the average UEG rate used in setting the cogeneration rate increases dramatically. This occurs because the fixed monthly costs allocated to UEG customers must be spread over a much smaller volume of gas. This problem is particularly acute during periods of UEG curtailment, or economic fuel switching by UEG customers.

In order to address this problem, SoCal proposes to set the cogeneration rate for the ACAP period on the basis of the forecast average UEG rate, rather than the recorded lagged UEG rate. This would eliminate rate swings due to both curtailment and fuel switching.

SCE, TURN, and SCUPP/IID support SoCal's recommendation. SCE supports the proposal because it addresses the problem of wide month-to-month variations in the cogeneration rate, but also because it would eliminate what SCE views as a perverse incentive which presently exists for SoCal to curtail UEG customers. SCE points out that curtailment of UEG customers increases the lagged-recorded average UEG rate. This in turn causes the cogeneration default rate and SoCal's revenues from cogeneration customers to increase.

CCC, CSC, Kelco, and DGS also support SoCal's proposal, but only if this modification in gas rate design policy is accompanied by a similar change in the method by which qualifying facility (QF) payments are calculated. They oppose SoCal's recommendation unless this "linkage" between the cogeneration gas rate, and the method of calculating payments to QFs is maintained.

SDG&E opposes SoCal's recommendation on two grounds. First, SDG&E argues that the proposal of SoCal would place increased emphasis on the accuracy of UEG throughput forecasts and would make this already controversial issue in ACAP proceedings far more controversial. Secondly, SDG&E argues that the problem SoCal's proposal is intended to address has been greatly overstated. SDG&E contends that cogenerators are adequately protected under the present rate setting method because even when fuel switching and UEG curtailment do drive the average UEG rate up, cogenerator's rates increase only up to the otherwise applicable commercial or industrial rate. As a result, they never pay the extraordinarily high average monthly UEG rates which occur from time to time as a result of fuel switching and curtailment.

We agree with SDG&E that the problem cited by the cogenerators is greatly overstated. Even when UEG rates rise sharply due to curtailment or fuel switching, the impact on cogenerators is greatly reduced through the availability to cogenerators of the otherwise applicable commercial or industrial rate. SCE's observation concerning a theoretical incentive to curtail UEG customers inherent in the present method of calculating cogenerations rates is interesting, but has not been shown to have had any effect whatsoever on UEG curtailment.

Although we do not view the problem raised by cogenerators as particularly significant, we are open to constructive suggestions to improve the equity and administration of our present approach to cogeneration rate design. Considered in this light, we find SoCal's proposal worthy of consideration. It has the advantage of simplicity, would adequately address the problems caused both by fuel switching and by curtailment, and may be a reasonable alternative to our present approach. Cogenerator representatives have, however, uniformly opposed SoCal's recommendation unless it is tied to changes in the method of computing payments to QFs.

We cannot accept this condition. There is not presently the kind of linkage between the calculation of cogeneration gas rates and QF payment methodology CCC, CSC, Kelco and DGS allege, nor are we persuaded that PU Code § 454.4 requires any such linkage. Moreover, even if we were persuaded that there should be such linkage, we consider changes in the method of calculating QF energy payments beyond the scope of this, or any other ACAP proceeding. The ACAP process is in need of simplification and streamlining, and cannot be efficiently managed if issues such as modification of the method of calculating QF energy payments are introduced into these proceedings.

Since we view changes in QF payment methodology beyond the scope of this proceeding, and will not adopt any such changes in this proceeding, we consider cogenerators to be opposed to SoCal's proposal.

Because of the cogenerators' opposition, and because we are not persuaded that the problem is particularly significant, we will not adopt the recommendation of SoCal at this time. Until a more compelling case for modification of our cogeneration rate setting methodology is made, we will continue to set the cogeneration transportation rate on a lagged-recorded basis.

b. <u>Proposal to Include Oil Burn</u>

Kelco and CCC have recommended an alternate approach for addressing the swings in cogeneration rates caused by UEG curtailment and fuel switching. If the Commission does not accept the linkage which CCC, CSC, Kelco, and DGS advocate between cogeneration gas rate design and QF payment methodology, Kelco and CCC propose that the Commission set the cogeneration rate on the basis of the total UEG gas <u>and oil</u> throughput.

SDG&E, SCE, and PG&E all oppose this alternative. They argue that it would virtually guarantee that the cogeneration rate would be below the UEG rate, and thus would be inconsistent with the requirement of UEG rate parity required by PU Code § 454.4. SDG&E also argues that this proposal should be rejected because it would produce changes in gas rates when oil burns occur for reasons that are totally unrelated to UEG curtailment or fuel switching. Under the proposal of Kelco and CCC, the cogeneration rate would go down, for example, if oil was used as the replacement fuel during an unexpected nuclear plant outage even though UEG gas rates may remain completely unaffected. Moreover, under some circumstances the proposal of Kelco and CCC could result in double counting of oil in the existing rate setting formula.

We agree with the arguments of SDG&E, SCE, and PG&E. The proposal of Kelco and CCC would guarantee that the cogeneration rate would be below the UEG rate. It would also result in changes in the cogeneration rate completely unrelated to changes in the average UEG gas rate. For these reasons, we will continue our present practice of basing the cogeneration rate on the average lagged UEG gas rate.

c. Proposal to Make Rate UEG Specific

CCC also proposes that cogenerator transportation rates be determined separately for each electric utility within SoCal's service territory.

This recommendation was not well developed, would add further complexity to an area in need of simplification, and therefore will not be adopted.

d. Start-up and Igniter Fuel

Cogenerators are currently charged gas transportation rates that are based on the average of all UEG transportation rates. DRA recommends that UEG igniter fuel service should be excluded from the calculation of the average UEG rate charged to cogenerators. SCE and SoCal oppose this recommendation and submit that the issue was previously resolved by the Commission in D.87-12-039.

We agree with SCE and SoCal. This issue was previously addressed and resolved in D.87-12-039 at p. 102 where we stated:

> "The average UEG transportation rate will be the total fixed and variable charges charged to the UEG customer for transmission service, including the transmission charges for igniter fuel in a given month divided by total UEG throughput during the same month." (Emphasis added.)

e. Effect of Long-Term Contracts

SoCal has signed long-term contracts with both SCE and SDG&E and proposes that they be excluded from consideration in calculating the cogeneration transportation rate.

CCC, CSC, and Kelco all object to SoCal's proposed method of treating long-term contracts in calculating the cogeneration transportation rate. We will not, however, address their objections at this time. The Commission is considering whether to approve the long-term contracts SoCal negotiated with SCE and SDG&E in C.89-05-016. The assigned ALJ has recommended that the contracts be disapproved. For purposes of this decision, we are assuming that the proposed ALJ decision will be adopted. For this reason, we do not consider this issue ripe for decision. We will reconsider the issue, if and when the volume of gas subject to long-term contracts is sufficient enough to have a material effect on the calculation of the cogeneration rate.

4. <u>EOR Default Rate</u>

SoCal has proposed to include in its tariff an EOR default rate of 4.569 cents per therm. TURN and SCUPP/IID both object to the establishment of a special default rate for EOR customers. They object on grounds that the proposed rate is substantially lower than any other noncore transmission rate, there is no necessity for such a rate because EOR customers have proven quite capable of securing favorable contracts from SoCal, and there is no justification for charging less than cost based rates in the absence of such a special contract.

We agree with TURN and SCUPP/IID. EOR customers have proven more than able to negotiate special contracts with SoCal to suit their needs. In the absence of such a special contract, we conclude that EOR customers should be required to pay a rate equivalent to the industrial default rate.

5. <u>UEG Issues</u>

a. <u>Proposals to Reallocate Risk</u>

Several proposals were made by DRA, SCUPP/IID, and others to change UEG rate design. The changes recommended were: (1) to use recorded UEG throughput instead of forecast throughput for determining the UEG demand charge; (2) to replace the two tier UEG rate design with a single volumetric rate; and (3) to increase the percentage of return on equity and tax costs allocated to the volumetric charge from the present 25% to 100%.

Each of these proposals would result in changing the allocation of risk associated with UEG throughput. Increasing the costs allocated to the volumetric charge and eliminating the present two tier UEG rate structure with a single volumetric rate would make more of the revenue requirement allocated to UEG dependent upon sales, and would thereby increase risk. The proposals to base the demand charge on recorded throughput would essentially reduce the demand charge to a delayed volumetric charge and would also put SoCal at increased risk.

The ACAP program is still quite new, and our experience with the program at this point in time is insufficient for us to consider making changes which significantly increase utility risk without a compelling reason. No such compelling reason has been offered in justification of these changes to UEG rate design. In addition, the present two tier rate has the effect of making incremental gas more competitive with the cost of alternate fuels and purchased power. As a result, this rate design structure gives UEG customers leverage in negotiating favorable non-gas fuel and power purchases. This leverage is reduced to the extent volumetric charges are increased. This is another factor which mitigates against the proposals made to modify UEG rate design.

For these reasons, we will maintain the current basis for setting UEG rates, and the current two tier rate structure.

b. <u>Treatment of UEG Igniter Fuel</u>

SCE and SCUPP/IID have proposed excluding distribution, customer-related costs, and conservation costs from the average core transmission rate to be charged for UEG igniter fuel. In support of this request, they argue that none of these costs are properly allocable to igniter fuel service.

SoCal opposes this recommendation and argues that issue was already decided in D.88-03-085, when the Commission stated that, "...we will treat ignitor fuel as core load for cost allocation and rate design purposes in SoCal's first cost reallocation proceeding." (D.88-03-085, mimeo. p. 28.) In addition, SoCal notes that the effect of the SCE, SCUPP/IID proposal would be to reduce the UEG igniter fuel charge from 30.712¢/therm to 8.767¢/therm.

When we stated that igniter fuel would be treated as core load for cost allocation and rate design purposes in SoCal's first ACAP, we intended that the UEG customers pay an equitable rate for the additional security of this high priority supply. We intended that a rate similar, although not necessarily identical to the core transmission rate should be applied to this UEG service. The rate proposed by SCE does not even approach the core transportation rate, and thus would permit SCE to receive the security of this supply without paying any significant percentage of the associated costs. We are not persuaded by the arguments of SCE and SCUPP/IID, and will apply the core transportation rate to UEG igniter fuel in this proceeding.

c. Proposed UEG Discount Adjustment

SCE recommends that the Commission adopt UEG rates that are no higher than the cost of other alternatives available to UEG customers, and that a UEG "discounting methodology" be adopted to allow SoCal to recover the cost of providing discount rates to UEG customers. SCE recommends that this discount methodology be structured in a manner similar to the "TURN method" the Commission has adopted for allowing SoCal to recover the costs associated with providing discount rates to industrial customers.

We are not persuaded that any such adjustment mechanism is necessary. The Commission can take all of the factors SCE has cited into consideration in setting the UEG rate without the adoption of any special discounting methodology. Moreover, the Commission has allowed SoCal to negotiate special contracts with discount rates where necessary to preserve load and maximize the contribution to fixed costs. SCE should be well aware of this option since the company has negotiated just such a contract with

SoCal. The contract is presently before the Commission for consideration in C.89-05-016.

6. Master-Meter Discount

Mobilehome parks that are master-meter customers of SoCal receive a rate discount to compensate them for the cost of providing submetered service to mobile home park residents. The discount under SoCal's current tariff (Schedule GS) is $5.40/month, and is obtained through retention of the $3.10 per space monthly customer charge plus a $.07561 daily per space credit by the park owner.

WMA, a statewide association of mobilehome park owners, has recommended that the master-meter discount be increased to $6.36/month. Their recommendation is based upon the cost SoCal has estimated it incurs for providing comparable submetered service. WMA has also cited cost studies done for the PG&E and SDG&E service territories in support of its recommendation.

SoCal and DRA have proposed no change in the amount of the discount.

PU Code § 739.5 governs the establishment of the master-meter discount. The statute provides in part,

> "The commission shall require the corporation furnishing service to the master-meter customer to establish uniform rates for master-meter service at a level which will provide a sufficient differential to cover the reasonable average costs to master-meter customers of providing submeter service, except that these costs shall not exceed the average cost that the corporation would have incurred in providing comparable services directly to the users of the service." (PU Code § 739.5 (a).)

The statute clearly requires that the discount be based upon the costs to the master-meter customer of providing submeter service, not the comparable costs of the utility. The utilities' cost of providing comparable service is relevant only as an upper limit on the costs which can be reflected in the discount.

In order to meet the requirements of the statute, WMA must present credible evidence of the average reasonable costs master-meter customers have incurred in providing submeter service. WMA should be well aware of this requirement since this issue has been considered by the Commission in prior proceedings. See D.89907 (1979) 1 CPUC 2d 172, 197. No evidence of the costs incurred by master-meter customers in SoCal's service territory was offered. WMA instead sought to rely upon evidence of SoCal's costs, and cost studies of other service territories. Neither of these are a sufficient basis upon which to modify the amount of the discount.

Since WMA has failed to meet its burden of proof, no change will be made in the master-meter discount. We welcome WMA to raise this issue again for our consideration when a study of the costs incurred by master-meter customers in SoCal's service territory has been prepared.

7. Long Beach Volumetric Rate

In D.87-12-039, we adopted a wholesale rate design consisting of a demand charge and a volumetric rate. We encouraged SoCal and its wholesale customers to determine the volumetric rate through negotiation. We indicated that the rate should bear some relation to the UEG volumetric rate, and could vary between the average UEG volumetric rate and 5% of all costs assigned to the wholesale customer.

Long Beach and SoCal have apparently been unable to negotiate a volumetric rate satisfactory to both parties. Long Beach has voiced strong objections to the rate SoCal proposes for wholesale customers, primarily on grounds that it is allegedly anticompetitive. The proposed rate is substantially above the rate SoCal proposes to charge SCE. As a consequence, Long Beach is effectively prevented from competing with SoCal for SCE load that, aside from these price considerations, Long Beach alleges it has the ability to serve. Long Beach requests that the Commission set the volumetric portion of the wholesale rate "at the low end of the range specified in D.87-12-039".

SoCal has responded by pointing out that the company is simply continuing the rate design last established by the Commission, and that Long Beach did not even sponsor a witness to recommend an alternative rate.

The rate SoCal has proposed is equal to the volume-weighted average of SoCal's proposed UEG Tier I and Tier II volumetric rates. We view this rate as within the range of reasonableness for wholesale customers. The argument Long Beach offers in its brief concerning the anticompetitive effect of this proposed rate design, may warrant further consideration, but there is no evidence in the record concerning the competitive issues that Long Beach has raised. We invite Long Beach to raise this issue on the evidentiary record in SoCal's next ACAP, or by way of a separate complaint. Until a more complete record is developed on this issue, we will maintain our present approach to wholesale rate design.

8. <u>Take-or-Pay Costs</u>

As previously indicated, we have adopted the DRA's recommended approach to allocation of the direct billed portion of interstate pipeline take-or-pay costs. In developing the rates contained in Appendix C to this decision, we have assumed that SoCal will elect to absorb 80% of these take-or-pay charges and absorb the remaining 20%. The actual allocation of take-or-pay costs between volumetric and charges cannot be determined until SoCal notifies us of its election under the alternatives proposed by the DRA and adopted in this decision. We will order SoCal to file an advice letter within 30 days of the date of this decision to indicate its election, and to implement rate changes consistent with its election. We have also invited SoCal to include within its comments on this proposed decision, any comments it may have on this proposed procedure for implementing our adopted method of allocating direct billed take-or-pay costs.

IV. SDG&E Issues

A. Gas Throughput

There are differences in the DRA and SDG&E forecasts of both SDG&E retail and non-retail throughput. The most significant differences are in their forecasts of UEG throughput.

1. Retail Throughput

DRA's forecast of total retail throughput for SDG&E is 692.3 MMth. SDG&E forecasts 688.6 MMth. The primary difference between the two forecasts is in the noncore sector where DRA exceeds SDG&E by 22 percent.

	DRA (MMth)	SDG&E (MMth)
Residential	324.8	328.7
Commercial	107.1	106.8
Noncore (excluding cogen)	50.4	41.3
Cogeneration	212.4	212.4

Both DRA and SDG&E developed throughput forecasts for the residential and commercial core classes through the use of econometric models. The models used incorporated a variety of different input assumptions such as weather, the price of natural gas, and economic activity in the service territory, but we find DRA's approach preferable because it also includes a wider variety of econometric variables. DRA included personal income and employment variables which SDG&E did not incorporate. Accordingly, we have adopted DRA's throughput forecasts of residential, core commercial, and noncore customer classes.

We also find DRA's forecast of noncore throughput more persuasive than SDG&E's. DRA used an econometric model to forecast noncore demand. SDG&E used a trend analysis. DRA has forecast slightly greater noncore demand for the ACAP period than was recorded in 1988, but recommends that we adopt the same demand as 1988 for forecast purposes. SDG&E has failed to justify to our satisfaction the significant decline in noncore demand the company forecasts. Accordingly, we have adopted DRA's noncore forecast of 50.4 MMth.

DRA accepted SoCal's forecast of 212.4 MMth for cogeneration throughput, and we will adopt the samo value.

2. UEG Throughput

SDG&E forecast UEG (interdepartmental) gas throughput of 201 MMth. This compares to much higher estimates of 384 MMth by DRA and 351 MMth by SoCal. The differences between these forecasts is primarily a result of differences in forecast oil and gas prices, and different forecasts of UEG supply and capacity curtailments. All models produced similar throughput forecasts ranging from 372 MMth to 394 MMth when these differences were eliminated.

Forecast oil and gas prices are critical to UEG throughput estimates because SDG&E will have an economic incentive to fuel switch anytime that the dispatch price of oil falls below the dispatch price of gas. SDG&E predicts that this situation will occur during six of the twelve months of the ACAP period. SoCal has forecast economic fuel switching during three months. DRA has forecast no economic fuel switching. Some of the difference between the SDG&E and SoCal forecasts is also a result of analytic errors in the development of SoCal's forecast.

SDG&E's forecast is based upon the company's forecast that LSWR prices in the Singapore market will vary between $12.15 and $14.06/Bbl during the ACAP period. SoCal's estimate is premised upon LSWR ranging between $13.80 and $14.65/Bbl. Since we have adopted a forecast average price of LSWR of $16.25/Bbl and expect more stability in oil prices over the ACAP period than has been experienced in the recent past, we forecast far less economic fuel switching than either SDG&E or SoCal. We also expect less fuel switching because it appears that neither SDG&E nor SoCal have adequately accounted for the increasing competition between alternate fuels that has been promoted by changes in the gas industry. We expect changes in oil prices to have an increasing effect on gas prices. As a result of the LSWR price we have adopted and increasing competition between gas and alternate fuels, we do not expect economic fuel switching except during a relatively short period during the winter months.

We have not attempted to quantify the amount of fuel switching which may occur in this proposed decision. Fuel switching is likely to occur only during the peak winter months. This is also the period of time that we forecast UEG curtailment. We have assumed, for purposes of this proposed decision, that UEG curtailment will equal or exceed economic fuel switching.

Significant fuel switching by SDG&E UEG is far more likely than by other SoCal customer classes however. This is primarily due to slightly lower assumed alternate fuel prices due to SDG&E's ability to use less expensive higher sulfur content oil (LSFO). We recognize the possibility that the models run by DRA, SoCal, and SDG&E to forecast fuel switching may produce results which differ from our assumption that curtailment will offset fuel switching. As a consequence, we will permit any of the parties, whose models have been explored on the record in this proceeding, to include in their comments, the amount of fuel switching their model predicts using our adopted oil, gas, demand, and curtailment values. We will consider any such information offered, together with the record testimony on the models used, prior to issuing a final decision in this proceeding.

We have adopted a UEG throughput forecast for SDG&E of 305 MMth. This value has been derived from the DRA's forecast of SDG&E UEG demand (384 MMth) less the level of curtailment we expect SDG&E to experience during the ACAP period (79 MMth).

B. Cost of Gas

1. Core and Noncore WACOG

SDG&E forecasts its gas demand will be supplied using spot gas purchases and through the use of gas purchased under longer term contracts indexed to the spot price. As a result, SDG&E forecasts that both its core and noncore WACOG will average $2.25/MMBtu at the California border during the forecast period. DRA forecasts that SDG&E's core and noncore WACOG will average $2.19/MMBtu at the border. SoCal forecasts SDG&E's core WACOG to average $2.49/MMBtu, and noncore WACOG to average $2.36/MMBtu.

SDG&E provided little support for its gas cost forecast beyond that discussed above concerning the cost of gas to SoCal. For the reasons discussed above, we will adopt DRA's forecast.

2. Take-or-Pay Costs

The allocation of direct billed interstate pipeline take-or-pay costs has a direct effect on the cost of gas to SoCal and SDG&E.

The allocation of take-or-pay costs direct billed to SoCal was a hotly contested issue, primarily because of the recommendations of DRA and Salmon/Mock to adopt an allocation approach which allocates risks and costs related to take-or-pay recovery to SoCal's shareholders as well as SoCal's ratepayers.

The allocation of direct billed take-or-pay costs to SDG&E was treated somewhat differently by the parties. SDG&E, like SoCal, seeks to recover 100% of direct billed take-or-pay costs from its ratepayers through demand charges with full balancing account protection. DRA has recommended that SoCal be given an option of recovering take-or-pay costs through volumetric rates, or recovering $4 through demand charges for every $1 SoCal agrees to absorb, but DRA has not extended this recommendation to SDG&E. Instead, DRA recommends that take-or-pay costs allocated to SDG&E be recovered only through volumetric rates. Salmon/Mock also appear to have treated SDG&E differently. They have limited their recommendation to SoCal, and have stated no position with regard to the recovery of take-or-pay costs by SDG&E.

We have considered the arguments of all parties on this issue, and conclude that the policy reasons supporting our decision to adopt DRA's approach to the allocation of take-or-pay costs direct billed to SoCal apply equally to SDG&E. We find no good reason to extend SoCal, and deny to SDG&E, the option of absorbing a portion of take-or-pay costs and recovering a larger portion through demand charges. Accordingly, for the reasons discussed more fully above with regard to SoCal's application, we will adopt the same optional approach to allocate take-or-pay costs direct billed to SDG&E that we have adopted for SoCal.

C. <u>Non-Gas Costs</u>

SDG&E's non-gas costs consist of its previously authorized gas margin and other fixed costs allocated to SDG&E by SoCal.

Under the terms of the proposed contract, fixed costs allocated to SDG&E by SoCal would be limited to $75 million, and no issues would be in dispute concerning SDG&E's non-gas costs. Several issues were raised, however, concerning the allocation of fixed costs in the absence of the long-term contract. Since we are assuming that the long-term contract between SDG&E and SoCal will not be approved, we will address these non-gas cost issues.

The issues raised concerning SDG&E non-gas costs include: (1) whether SDG&E should be allocated a portion of SoCal's Lost and Unaccounted for gas (LUAF); (2) the basis for allocating SoCal's company use gas costs to SDG&E; (3) the basis for allocating the cost of SoCal's Moreno to Rainbow Lines 1027 and 1029, and the Coastline Orange County Line to SDG&E; (4) whether SDG&E should be allocated a portion of SoCal's carrying cost for gas in storage; (5) whether SDG&E should be allocated any portion of SoCal's long-term contract shortfall, and (6) proposed changes in the allocation of noncore balancing account undercollections to SDG&E.

Each of these issues have been resolved in our preceeding discussion concerning SoCal ACAP issues.

In addition, SDG&E has requested that the balance recorded in its CSA be amortized in rates in this proceeding. SoCal made a similar request. For the reasons discussed in more detail with regard to SoCal's request, we will not allow SDG&E to amortize the balance in its CSA, and will abolish the account.

D. Rate Design

1. Carrying Cost Gas in Storage

DRA proposes allocating the carrying costs of gas in storage to SDG&E's D2 demand charge. SDG&E proposes to recover these costs through the D1 demand charge, but has no objection to DRA's proposal.

Storage related costs are seasonal costs. It is our policy, as stated in D.86-12-009, to allocate costs which are seasonal in nature to the D2 demand charge. We find no reason to deviate from this established policy in this instance.

2. Seasonal Differential for Core Commercial

SDG&E established seasonally differentiated rates for the core commercial class in accordance with D.87-12-039. Under the current rate design, the seasonal differential causes bills for low usage customers to be as much as two times the average summer bill. SDG&E proposes to reduce the current winter/summer differential by one half in order to moderate the seasonal bill fluctuations of low usage customers.

DRA is opposed to SDG&E's recommendation. DRA proposes a slight increase in the seasonal differential.

We share SDG&E's concerns about the impact of wide seasonal variations in core commercial bills, and as a result of this concern will adopt SDG&E's recommendation.

3. <u>Cogeneration Parity Rate</u>

Currently, the average cogeneration transportation rate is based on the recorded average UEG gas rate filed monthly, lagged by two months. This rate setting approach has resulted in wide variations in the cogeneration rate during periods of UEG curtailment, or economic fuel switching by UEG customers.

In order to address this problem, SoCal has proposed setting the cogeneration rate on the basis of the forecast average UEG rate. Kelco and CCC support the implementation of SoCal's rate design approach in SDG&E's territory, but only if this modification in gas rate design policy is accompanied by a similar change in the method by which QF payments are determined. If the Commission does not accept the linkage which Kelco and CCC advocate between cogeneration gas rate design and QF payment methodology, Kelco and CCC propose an alternate approach to setting the cogeneration gas rate. Under their alternate approach, the cogeneration rate would be based upon the total UEG gas <u>and oil</u> throughput.

SDG&E opposes all of the changes advocated by SoCal, Kelco, and CCC to cogeneration rate design.

For the reasons discussed above concerning these same issues raised in SoCal's application, we will not adopt the changes advocated by Kelco and CCC. We will continue to set SDG&E's cogeneration transportation rate on the basis of the lagged recorded average UEG rate.

4. <u>Igniter Fuel</u>

DRA has proposed that igniter fuel revenues be excluded from the calculation of the average UEG transportation rate used in setting the cogeneration parity rate. SDG&E opposes DRA's recommendation on grounds that it is inconsistent with Commission policy stated in D.87-12-039.

We agree with SDG&E. This issue was considered and decided in D.87-12-039, and we find no reason to deviate from our prior decision on this matter.

5. Borrego LNG Service

SDG&E proposes a 10% average rate increase for liquified natural gas (LNG) service to the Borrego area. This proposed increase will bring rates more closely in alignment with the cost of providing this service. There was no opposition to this proposal, and it will be adopted.

V. Other Issues

A. Information Concerning Portfolio Construction and Management

TURN has recommended that SoCal be required to provide additional information in future ACAPs concerning portfolio construction and management. TURN claims that such information would enhance the ability of the parties and the Commission to evaluate throughput and cost of gas issues. SoCal objects to TURN's proposal on grounds that the information TURN seeks on purchasing practices and storage objectives would turn every ACAP case into a "pre-reasonableness review on gas costs and supply operations.

In D.89-04-080, we took steps to require utilities to provide information in their ACAP applications concerning portfolio construction. We do not find any need for requiring information beyond that already required. If TURN needs additional information relevant to ACAP issues in a particular case, the additional information can be obtained through the Commission's discovery processes. We will not establish any new informational requirements for ACAP proceedings concerning gas utility portfolio construction or management at this time.

B. Proposed Revisions to Tariff Rule 23

Edison requests that the Commission revise SoCal's tariff Rule 23 to add guidelines to define when economic curtailment may be conducted.

It is far from clear what revisions to SoCal's tariff Rule 23 Edison is recommending, and no record was developed on the implications of any such change. Moreover, the ACAP process is not well adapted to consideration of changes in operational guidelines for gas utilities. Any such recommendations should be addressed in a separate proceeding initiated for the purpose of reviewing the relevant tariff rules, such as the petition of Long Beach to modify D.86-12-010. We will not consider changes to SoCal's tariff Rule 23 in this proceeding.

C. <u>Motions Concerning Update of Record</u>

On September 15, 1989 SoCal filed a petition to set aside submission and to reopen the proceeding for the purpose of receiving updated information on balancing account balances, gas prices, and volumes reflecting developments which occurred after the close of hearings.

The petition was granted by the ALJ. the ALJ's ruling permitted SoCal, SDG&E, and any other party to file updated information reflecting the following developments which were unknown or unavailable at the time of hearings: (1) executed gas purchase agreements including GIC nominations; (2) FERC orders and accepted FERC tariff filings; (3) uncontested settlement agreements filed with FERC; (4) recorded gas costs not yet available at hearings; and later-recorded amounts in various balancing and tracking accounts.

Updated information was subsequently filed by both SoCal and SDG&E. Following the receipt of the updated information several parties filed comments on the updates in accordance with the procedure established in the ALJ's ruling. TURN and SCUPP/IID did not object to the updated information, but contended that it was incomplete, and that additional information should also be required.

TURN expressed the belief that new information concerning possible lower prices for direct purchase gas supply contracts,.

which make up approximately 58% of the core portfolio, may be available, and could be incorporated into the decision in this proceeding. TURN suggests that the Commission direct SoCal to provide the actual cost of new one-year direct purchase gas supply contracts for the record in its comments on the ALJ's proposed decision (along with workpapers), in order to allow the Commission to reflect the most up-to-date information in its final decision.

SCUPP/IID request that SoCal be directed to provide the Commission with copies of any curtailment notices it sends to customers and requests that the Commission take official notice of such curtailment notices in resolving throughput questions raised in this proceeding.

It is desirable for the Commission to base its decisions on the most recent information available, but this objective must be balanced against the rights of the parties to Commission proceedings and our own need to test the credibility, reliability, completeness and accuracy of the information presented. The updated information provided by SoCal and SDG&E is of a noncontroversial and readily verifiable nature. As a consequence, reopening the record to receive this information will not adversely affect the position of any party on any issue contested. We therefore concur with the initial ruling of the ALJ, and will receive the updates of SoCal and SDG&E in evidence.

The additional information requested by TURN and SCUPP/IID does not appear to be quite of the same nature, particularly the information concerning curtailments that SCUPP/IID seeks to have introduced. Information concerning curtailments is likely to be subject to varying interpretations, and may be subject to legitimate challenge that cannot properly be resolved outside of the hearing process. At some point, notwithstanding continuing developments, the evidentiary record in each proceeding must be closed and the case submitted for decision. That point has been reached in this proceeding. The requests of TURN and SCUPP/IID to require additional updated information from SoCal are denied.

D. Motion of SCE for Interim Rate Relief

On August 2, 1989 Edison filed a motion requesting interim rate relief for the period between October 1, 1989 and the date rates established in this proceeding are implemented. Edison is requesting interim rate relief because the decision in this proceeding will be decided later than anticipated by the Commission when it established the ACAP hearing schedule. Edison requests that its rates be reduced on an interim basis by approximately $72 million annually which it alleges is the "minimum rate reduction that the ACAP parties are proposing for UEG transportation service."

The motion is opposed by SoCal, DRA, SDG&E, and CSC.

We will deny motion. To grant Edison the "minimum decrease" it seeks on an interim basis would require the Commission to evaluate numerous arguments raised in the proceeding that affect UEG rates, would also require consideration of potential adjustments to the rates of other customer classes, such as cogenerators that are entitled to UEG rate parity by statute, and would take considerable time and effort that could better be spent preparing a final decision in the ACAP.

E. Motion to Strike Long Beach Brief

On September 15, 1989 SoCal filed a motion to strike portions of the opening brief of Long Beach. The motion was based upon grounds that the brief relies on allegations of fact outside the evidentiary record and seeks to introduce new factual material into the record through a written declaration that could and should have been presented through a witness subject to cross-examination during evidentiary hearings in this case.

Long Beach has replied to SoCal and asserts that no evidence is required of Long Beach in order for the Commission to address the issues it has raised.

Most of Long Beach's brief is based upon argument of counsel. This is perfectly permissible and proper. Parties are under no obligation to introduce evidence when they have chosen instead to rely upon argument of counsel or citation to prior precedent. SoCal is correct, however, in noting that Long Beach has made several allegations of fact which are not supported by record evidence. These include allegations concerning (1) the commitment of the Long Beach Gas Department to pass through savings received as a result of cost reallocation to its residential customers; (2) payments the Long Beach Gas Department makes in lieu of franchise fees to the City of Long Beach; and (3) requests by Long Beach for transportation service from PITCO and POPCO. The Commission will disregard extra-record factual claims concerning these subjects in evaluating the arguments made on issues raised by Long Beach, but finds insufficient cause to strike any portion of the brief of Long Beach. SoCal's motion is denied.

F. Request of TURN for Finding of Eligibility for Compensation

TURN has requested a finding that it is eligible for intervenor compensation under Rule 76.54(a) of the Commission's Rules of Practice and Procedure.

We conclude that TURN has demonstrated significant financial hardship within the meaning of Rules 76.52(f), 76.53, and 76.54(a) as revised in D.85-06-126, and is found eligible for compensation.

G. SDG&E Transcript Corrections

By letter dated August 22, 1989, SDG&E requested that certain corrections be made to the official transcript in this proceeding. We accept the requested changes. They will be made in the Commission's official transcript of the proceeding.

VI. Issues Deferred

A number of issues which arose in the proceeding were deferred by the ALJ to a subsequent phase of this proceeding, or to other proceedings. Among the issues deferred are: (1) SoCals' A&G and LUAF cost allocation studies, and changes in cost allocations resulting from these studies; (2) whether cogenerators that do not meet FERC efficiency standards set forth in Section 292.205 of Title 18 of the Code of Federal Regulations should be entitled to UEG-parity gas rates under PU Code § 454.4; (3) whether the cogeneration gas limitation should be calculated on the basis of incremental energy rates (IER) or incremental heat rates (IHR); and (4) the adjustment recommended by DRA for past-due franchise fees paid to City of Rancho Cucamonga. All but the last of these issues will either be considered in Phase II of this proceeding, or in a more generic proceeding. The DRA agreed to defer consideration of the past-due franchise fees to SoCal's 1988-89 reasonableness review.

Findings of Fact

1. The econometric models of both SoCal and DRA produced acceptable results when run to "backcast" 1988 demand, although DRA's model produced results closer to actual recorded demand.

2. SoCal's gas throughput forecast is based upon a model that does not include 1988 data, and thus does not incorporate the effects of changing customer behavior under the new gas industry structure.

3. DRA's alternate fuel price forecasts are based upon DRA's forecast price of LSWR in the Singapore market, and upon trends in the prices of No. 2 and No. 6 fuel oil.

4. DRA forecast LSWR Singapore using several statistical methods that DRA has employed in prior ECAC proceedings before the Commission.

5. SoCal's RACC forecast is based upon the experience and judgement of SoCal's witness, is subjective in nature, and is not based upon or supported by any quantitative or statistical analysis.

6. Although the oil price forecasts introduced in this proceeding range fairly widely, the data upon which these forecasts have been based show signs of increasing price stability.

7. DRA's statistical approach to oil price forecasting is preferable to SoCal's heavy reliance on informed judgement unsupported by statistical analyses.

8. DRA's forecast may have been influenced, to a greater degree than warranted, by significant price increases for LSWR experienced in the first half of 1989.

9. Based upon the evidence offered in this proceeding, an average LSWR price of $16.25/Bbl is reasonable for the ACAP period.

10. $4.15/MMBtu is a reasonable average price for Los Angeles No. 2 diesel fuel, and $2.86/MMBtu is a reasonable average price for No. 6 low sulfur fuel oil for the ACAP period.

11. We find DRA's methodology for forecasting spot gas prices, which includes two models based upon historic spot gas prices, preferable to SoCal's approach.

12. DRA's spot gas price of $2.19/MMBtu appears reasonable in light of historic spot gas prices and will be adopted.

13. There is insufficient evidence to warrant any upward adjustment to DRA's spot gas price forecast to reflect the gradually changing gas demand/supply balance.

14. Uncontroverted evidence indicates that the current national gas surplus will continue to exist throughout the ACAP period.

15. SoCal has insufficient capacity to serve all of the demand that DRA and SoCal forecast using only its own facilities and interstate pipeline facilities directly connected to SoCal's system.

16. The only way SoCal can serve all of the demand forecast during the ACAP period is through interutility transportation service from PG&E, if that service is available when needed, and at a sufficient capacity level.

17. SoCal forecasts that it will have available, and will be able to utilize, 150 MMcf/d of PG&E interutility transportation service, expressed as an average daily amount over the 12-month ACAP period.

18. SoCal's take-away capacity from the PG&E system is 1,070 MMcf/d, subject to gas availability and local pipeline pressure at any given time.

19. SoCal's estimate of interutility capacity to SoCal from PG&E is based upon dry year data.

20. It is our policy to forecast throughput in ACAPs on average year conditions.

21. An additional 162 MMcf/d of interutility transportation service to SoCal from PG&E should be available, over and above what SoCal has assumed, as a result of assuming average hydro conditions on the PG&E system.

22. This increase will be largely offset by the shutdown of Rancho Seco.

23. The shut down of Rancho Seco will increase PG&E's UEG requirements by approximately 123 MMcf/d.

24. 189 MMcf/d is a reasonable forecast of average available interutility transportation capacity from PG&E to SoCal for the ACAP period.

25. SoCal maximized daily storage injections in the spring of 1989 in order to reach the core protection level of 70 Bcf of gas in storage as early as possible.

26. SoCal filled all its storage fields to capacity by June 1, 1989 except Aliso Canyon.

27. Various figures, up to 700 MMcf/d, were introduced in this proceeding concerning SoCal's storage injection capacity.

28. SoCal contends that its injection capability is only 300 to 350 MMcf/d when all fields except Aliso Canyon are full.

29. 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.

30. The effect of coincident high demand on both the SoCal and PG&E systems can be mitigated through the effective use of storage.

31. It is unclear whether SoCal's gas balance model operates to maximize the level of service through the use of storage capability. SoCal offered no convincing evidence that effective use of storage could not increase average interutility capacity above the 150 MMcf/d level SoCal has forecast from PG&E through interutility sales.

32. We find that SoCal will have available a maximum storage injection capability of at least 300 MMcf/d, and up to 700 MMcf/d, during critical portions of the storage injection season.

33. We conclude that SoCal's injection capability will be sufficient for SoCal to accept the average annual 189 MMcf/d of gas we have estimated will be available to the company from PG&E over Line 300.

34. Daily operating records of El Paso Natural Gas Company (El Paso) for 1987 and 1988 indicate that the El Paso system had more than 14% of its capacity unused during this period.

35. 14% of El Paso's total capacity to California of 2890 MMcf/d equals 405 MMcf/d.

36. SoCal has assumed that it will utilize 96% of the 1750 MMcf/d of El Paso capacity connected to SoCal, after adjustment for scheduled maintenance and reduced summertime take-away capacity.

37. Increased experience with the new gas industry structure should bring improvement in the utilization of the El Paso system.

38. A 97% utilization factor on the El Paso system is reasonable to assume for the ACAP period which will result in an increase in the assumed usable capacity from SoCal's interconnection with El Paso of 17.5 MMcf/d.

39. The possibility of conditions occurring during the ACAP period under which SoCal would have an incentive for what has been described as "economic curtailment" has not been sufficiently demonstrated to warrant incorporation into the adopted throughput forecast.

40. SoCal's proposed "practical adjustment" to the discount adjustment calculation has the effect of reducing the incremental revenue forecast to be obtainable through discounting.

41. Although there undoubtedly are imperfections in SoCal's negotiation of rate discounts, the discount adjustment methodology can at best only approximate the actual revenue to be gained through discounting.

42. It is better policy to assume optimal rather than deficient rate discount negotiation as a basis for applying the discount adjustment methodology used to estimate the incremental revenue that gas companies can obtain through negotiating rate discounts.

43. There are features embedded within the discount adjustment calculation methodology that tend to offset imperfections in negotiation of rate discounts.

44. SoCal's industrial throughput forecast reflects a 6.5% decline from recorded 1988 levels.

45. SoCal attributes the majority of the decline it forecasts in commercial noncore throughput and industrial noncore throughput to an increase in cogeneration.

46. SoCal has not made a persuasive case that it has properly calculated or accounted for the cogeneration effect.

47. SoCal used data only through 1987 in developing its throughput forecast.

48. DRA's forecast of noncore commercial and industrial throughput appears somewhat high in light of the inputs assumed.

49. 20 MMdth for noncore commercial and 70 MMdth for noncore industrial are reasonable throughput forecasts for these classes.

50. A portion of the cogeneration included in SCE data is not gas fired and therefore will not increase gas demand or throughput.

51. Forecast throughput of 73 MMdth for the cogeneration (other than EOR) is reasonable for the ACAP period.

52. We do not foresee any significant economic fuel switching by SoCal's UEG customers during the ACAP period.

53. To the extent any economic fuel switching may occur, it is likely to occur only during a short period in the winter which is also the period of time that we have forecast UEG curtailment.

54. We expect UEG curtailment to exceed economic UEG fuel switching.

55. Since our UEG throughput forecast already reflects UEG curtailment during the period when economic fuel switching may occur, there is no need to separately forecast the amount of fuel switching.

56. Since we have adopted DRA's forecast spot gas price, it is reasonable to adopt DRA's UEG demand forecast which was developed using that gas price.

57. The noncore UEG demand of LADWP should be reduced by approximately 5 MMdth to correct errors cited by SCUPP/IID.

58. We are not persuaded of the necessity to adjust the throughput forecasts for Burbank or Pasadena.

59. SoCal's forecast of UEG igniter fuel volumes was not adequately supported.

60. SCUPP/IID's forecasts of UEG igniter fuel volumes is reasonable.

61. 152.6 MMdth is a reasonable UEG throughput forecast for the ACAP period.

62. Based upon the gas and oil price forecasts we have adopted, we conclude that there should be no significant economic EOR fuel switching.

63. To the extent that any economic EOR fuel switching may occur, it is likely to occur only during a short period in the winter and will most likely be offset by EOR steaming curtailment.

64. 150.9 MMdth is a reasonable EOR throughput forecast.

65. Since we have adopted a higher price for oil and a lower price for gas than SoCal and SDG&E assumed, we forecast far less economic UEG fuel switching by SDG&E than either company.

66. We have not attempted to quantify the amount of UEG fuel switching by SDG&E which may occur because fuel switching is likely to occur only during the peak winter months, which is a period of time during which we have forecast UEG curtailment.

67. We have assumed, for purposes of this decision, that curtailment of SDG&E UEG demand will equal or exceed economic fuel switching.

68. 101 MMdth is a reasonable throughput forecast for SDG&E.

69. Until we rule upon Long Beach's petition to modify D.86-12-010, Long Beach should be allocated a prorata portion of the curtailment we have forecast.

70. A reasonable forecast of Long Beach throughput is 23.9 MMdth based upon forecast curtailment of 4.6 MMdth.

71. A forecast core WACOG of $2.36/MMBtu is reasonable for the ACAP period.

72. A forecast of 605 MMth at weighted average price of $2.48 MMBtu is reasonable for California production.

73. 42 MMth at a weighted average price of $3.42 is a reasonable forecast for federal offshore gas.

74. 835 MMth at weighted average price of $2.30/MMBtu is a reasonable forecast for PITCO gas.

75. 114 MMth at $2.65/MMBtu is a reasonable forecast for POPCO gas supply.

76. 2548.1 MMth at a weighted average price of $2.42/MMBtu is a reasonable forecast for interstate pipeline and direct purchases.

77. 596 MMth of spot gas for the core portfolio at border price of 2.19/MMBtu which equates to a weighted average price of $2.22/MMBtu is a reasonable forecast.

78. 2075.3 MMth is a reasonable forecast of noncore supply.

79. $2.20/MMBtu is a reasonable forecast of the noncore WACOG.

80. Elk Hills purchases are discretionary purchases made through a competitive bidding process every four months.

81. It is reasonable to assume a forecast price of Elk Hills gas equivalent to the core WACOG.

82. $30,668,000 is a reasonable forecast for El Paso take-or-pay billings for the ACAP period, and $14,705,000 for El Paso take-or-pay billings prior to October 1, 1989.

83. A reasonable forecast of take-or-pay billings by Transwestern prior to October 1, 1989 is $47,370,000. There are no direct billed Transwestern take-or-pay liabilities for the ACAP period.

84. A reasonable forecast of take-or-pay billings by POPCO prior to October 1, 1989 is $625,000.

85. We take notice of the findings and conclusions of the FERC reached in Orders 380, 436, and 500 concerning the circumstances that gave rise to the gas industry's take-or-pay problems.

86. The take-or-pay costs now at issue in the industry arose as a result of contracts entered into in the late 1970's and early 1980's which was a period of gas shortages and rising prices. During this period, pipeline companies attempted, with the encouragement of the FERC, to maintain secure long-term supply reserves and often negotiated and signed contracts of 10 years or more which included "take-or-pay" provisions.

87. The high cost of gas under these long-term take-or-pay contracts had little initial effect on the marketability of the gas because the cost was rolled-in to the pipelines' computed average cost of gas along with other low price price-controlled gas for ratemaking purposes.

88. Elimination of customers' take-or-pay obligations in FERC Order 380, and a drop in the price of alternate fuol eventually brought the embedded cost of long term take-or-pay contracts well above competitive prices.

89. Pipelines reacted by refusing to transport third party gas when to do so would have the effect of displacing the pipeline companies' own deliveries. This had the effect of denying consumers access to gas at the lowest reasonable rate.

90. In Order 436 the FERC concluded that the prevailing pipeline practice of generally refusing to transport gas for third parties where to do so would displace their own sales was "unduly discriminatory" within the meaning of § 5 of the Natural Gas Act, 15 U.S.C. §§ 717 et seq. (NGA), and ordered pipelines to transport gas for third parties in competition with the pipelines' own supplies.

91. Order 436 resulted in significant new competition in the industry, particularly between pipelines and other gas sellers, and provided consumers with the economic benefits of more competitive wellhead prices.

92. Among the more problematic repercussions of Order 436 is the present industry take-or-pay problem. As pipeline customers took advantage of the new open access rules, pipelines' high priced supplies became unmarketable as more and more pipeline customers chose to purchase their own gas directly from producers or marketers for transportation. This resulted in drastic reductions in pipeline takes of high priced gas, and significant liability under the pipelines' take-or-pay contracts with gas producers.

93. FERC Order 500 provides two alternative mechanisms for pipelines to use to recover prudently incurred take-or-pay related costs. Under the first option, pipelines may recover 100% of prudently incurred costs through volumetric or commodity rates. Under the second option, pipelines are permitted to recover anywhere from 25% to 50% of their take-or-pay costs from customers through a fixed take-or-pay charge direct billed to pipeline customers, provided that the pipeline agrees to absorb an equal amount. Any amounts above what the pipeline is willing to absorb would be permitted to be recovered through a commodity surcharge, or volumetric surcharge, on pipeline throughput.

94. The costs incurred by El Paso and Transwestern to buyout and buydown their accrued take-or-pay liability with producers are the costs subject to recovery through the alternative mechanisms provided for in Order 500.

95. Both El Paso and Transwestern have chosen FERC's "equitable sharing" approach and have chosen to allocate 25% of their take-or-pay costs to their shareholders and the remaining 75% to their customers.

96. SoCal claims that it is entitled to recover 100% of all take-or-pay costs, and proposes to recover the noncore portion through demand charges with full balancing account protection.

97. DRA recommends that the Commission adopt an equitable sharing mechanism, similar to that adopted by the FERC under which SoCal choose between two different methods of recovery: (1) recovering all take-or-pay costs through a volumetric surcharge without balancing account protection, or (2) recovering, through a direct billed demand charge, four times the percentage of direct billed take-or-pay costs that the company agrees to absorb. Under the second option, any remaining balance, after 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.

98. Salmon/Mock object to SoCal recovering any direct billed take-or-pay costs and allege that the only way to effect a truly equitable sharing of take-or-pay costs is to require SoCal to absorb all amounts billed in excess of the amount FERC permits the pipelines to recover through volumetric charges.

99. Parties to this proceeding have been on notice at least since we issued D.87-12-039 on December 9, 1987 that the allocation of take-or-pay costs would be an important issue to resolve in future ACAP proceedings.

100. Parties have also been on notice since April 12, 1989 when SoCal's application was filed, that the company was requesting full recovery of all take-or-pay costs from its customers.

101. SoCal has requested regulatory treatment which, in effect, assigns full responsibility for the economic and regulatory risks which gave rise to take-or-pay liability, and the consequential costs now being assessed, to its ratepayers.

102. We agree with the FERC that no one segment of the industry appears responsible for the take-or-pay problem and that under the circumstances, all segments of the industry, including distributors such as SoCal, should share some portion of the burden necessary to resolve the problem.

103. Balancing and tracking accounts are always established for the explicit purpose of facilitating further rate adjustments, and often further review of the costs booked to such accounts.

104. Market forces are likely to limit recovery of take-or-pay charges assessed through volumetric rates.

105. As a result of their elections under the equitable sharing mechanism adopted by FERC, El Paso and Transwestern will recover a maximum of 75% of their take-or-pay costs from their customers.

106. If one assumes that SoCal's customers will be paying 50% of El Paso and Transwestern take-or-pay costs through volumetric surcharges and that these costs are passed through to SoCal's

customers, then under all three proposals before us, SoCal will recover at least 67% of the take-or-pay costs passed through to California from El Paso and Transwestern to SoCal.

107. SoCal requests full recovery of the remaining direct billed amount which if granted would provide the company with 100% recovery.

108. Under the proposal of Salmon/Mock, SoCal would recover 67% of the take-or-pay costs billed to it, but would be required to absorb the remaining 33%.

109. If one assumes that SoCal elects to absorb the full $1 of direct billed amounts for every $4 billed, then under DRA's proposal, SoCal would recover 80% of direct billed amounts, but SoCal's customers would pay 93% of all take-or-pay costs billed to California. The remaining 7% represents the amount SoCal would absorb under these assumptions.

110. SoCal's request would require all segments of the industry to share the costs of resolving the industry's take-or-pay problems, except SoCal and is inequitable under the circumstances.

111. The proposal of Salmon/Mock would require SoCal to absorb a greater percentage of take-or-pay costs than El Paso or Transwestern and would also be inequitable.

112. Although SoCal received benefits from the changes in regulation of the gas industry including increased recovery of forecast costs included in base rates, and preservation of the company's market share, most of the savings obtained through reduced gas costs directly benefited SoCal's customers.

113. The DRA recommendation for allocation of direct billed take-or-pay costs will provide SoCal with a reasonable opportunity to recover take-or-pay costs and strikes a fair balance in allocating risks and costs between ratepayers and SoCal's shareholders.

114. El Paso Account 191 direct billed amounts are dependent upon the outcome of settlement negotiations in the El Paso general rate case at the FERC.

115. $49.2 million has been received by SoCal from El Paso as a result of the Southland settlement.

116. SoCal may receive substantial direct bills from El Paso and Transwestern during the ACAP period for recovery of Account 191 balances.

117. SoCal has received a $36.8 million direct credit with respect to the El Paso "Mid-Louisiana/RFX" proceeding.

118. The CCA account is a balancing account which was established by the Commission in D.92854 as part of the demonstration solar financing program. The purpose of the account is to reconcile authorized and expended costs for conservation related programs, and to allow recovery of reasonable conservation program costs.

119. The Angelus litigation arose from the Commission authorized WFCP and was brought by eight contractors who installed residential conservation measures pursuant to SoCal's WFCP program.

120. The contractors alleged various causes of action against SoCal including negligence, misrepresentation, conspiracy to monopolize, and conspiracy to prevent competition.

121. SoCal incurred approximately $3.86 million in legal fees and associated litigation costs related to the Angelus case and eventually settled the case by paying the plaintiffs $2.44 million.

122. Litigation and settlement costs are included in Accounts 923 and 925 on a forecast basis in SoCal's general rate cases, and SoCal was authorized $10,811,000 for Account 923 and $6,749,000 for Account 925 in the company's test year 1985 general rate case.

123. For a period of at least four years, from 1985 to 1988, SoCal booked conservation related claims expenses to base rate accounts.

124. Providing balancing account treatment for litigation and claims reduces, if not eliminates, any economic stake utilities have in claims and litigation.

125. There generally are strong policy reasons for ensuring that utilities retain a significant economic stake in litigation. Retaining an economic stake in litigation provides a significant incentive for utilities to minimize claims, litigation, and legal exposure by ensuring that company practices, procedures, and employee conduct conform to laws, regulations, and prudent business practices. It also provides an incentive to evaluate claims, litigation strategies, and settlement options in a realistic manner, and to take a cost effective approach to litigation and settlement negotiations. Balancing account treatment serves none of these policy objectives.

126. SoCal produces oil in connection with the operation of its Honor Rancho underground gas storage field.

127. Prior to May 1, 1988, Commission decisions explicitly required SoCal to credit revenues received for oil production incidental to operation of SoCal's gas storage fields to the CAM balancing account. Through this mechanism oil revenues were used to offset revenue requirement for the benefit of SoCal's ratepayers.

128. Since May 1, 1988 SoCal has booked oil revenues to the Miscellaneous Revenues account which is a base rate account. Revenues booked to this account do not receive balancing account treatment and are not used to offset revenue requirement, except on a forecast basis in each general rate case.

129. Since oil revenues were subject to balancing account treatment under the CAM procedure at the time of SoCal's last general rate case, they were not taken into account in forecasting the Miscellaneous Revenues account.

130. SoCal and DRA have agreed to include all prospective oil revenues on a forecast basis in Miscellaneous Revenues (above-the-line) in SoCal's test year 1990 general rate case.

131. As a result of accounting workshops held to develop new accounting mechanisms to implement the Commission's restructured regulatory program for the gas industry, DRA understood that oil revenues would be booked into the Other Revenue account that is part of the GFCA. A detailed accounting stipulation was developed as a result of these workshops and was later submitted to and approved by the Commission.

132. To allow SoCal to book oil revenues to the Miscellaneous Revenue account would result in a direct transfer of revenue from ratepayers and a windfall for SoCal.

133. SoCal's forecast of brokerage related costs of $1,494,000 was developed from 1983 cost data and includes only procurement related costs.

134. DRA reviewed data filed by SoCal in the company's 1990 general rate case and estimates brokerage costs of $3,878,000, which includes $2,378,000 for procurement related costs, and $1,500,000 for marketing related costs.

135. Salmon/Mock estimates SoCal's brokerage costs at $5.2 million.

136. The CSA was established for the purpose of tracking the difference between the monthly average UEG rate and the otherwise applicable commercial or industrial cogeneration rate.

137. SoCal has recorded $14.4 million in "shortfalls" in its CSA.

138. The balance in SoCal's cogeneration shortfall account is primarily a consequence of unexpected dramatic increases in the recorded average monthly UEG rate which resulted from UEG fuel switching and curtailments.

139. The present CSA account balance does not reflect any real revenue shortfall.

140. SoCal's CSA has not worked as intended, and is not likely to work as intended under any reasonably foreseeable set of circumstances.

141. SoCal has not adequately established when, or the extent to which EOR demand served through interutility transportation service by SoCal will be reduced during the ACAP period through construction of new facilities by PG&E.

142. Because PU Code § 739.6 restricts our ability to provide comprehensive solutions to cost allocation problems, there is a very real possibility that in remedying one perceived inequity, we may create or aggravate another.

143. Long-term contracts SoCal negotiates generally provide additional revenue to offset SoCal's fixed costs.

144. Long-term contracts Long Beach and SDG&E may negotiate can have the same beneficial effects for SoCal that SoCal's own long-term contracts have.

145. There has been no evidence offered concerning the long-term contracts that SDG&E and Long Beach may have signed, or the amount of any revenue shortfalls experienced by SDG&E or Long Beach as a result of such contracts.

146. The majority of company use gas is incurred for transmission of gas and for gas storage operations and is therefore related to throughput.

147. There has been no showing that the present method of allocating costs of SoCal transmission facilities to SDG&E has resulted in hardship or is inequitable within the meaning of PU Code § 739.6.

148. The service SoCal provides to Long Beach cannot be provided without the use of facilities located in public streets and rights of way spread throughout SoCal's service territory and as a consequence, at least some portion of the franchise fees SoCal pays to cities and counties throughout its service territory are incurred for the benefit of Long Beach.

149. The proposal of CIG/CLFP to eliminate the commercial and industrial demand charge would increase risk to SoCal, and would relieve commercial and industrial customers that fuel switch of cost responsibility for fixed costs associated with facilities SoCal maintains for their benefit when they choose to use gas.

150. The 4-month winter and 8-month summer seasons proposed by DRA for use in setting seasonally differentiated non-residential rates would allow rates to be designed that more closely match the incurrence of cost to meet peak winter demand and are the same currently used for developing seasonally differentiated noncore rates.

151. When UEG gas throughput is low, the average UEG rate used in setting the cogeneration rate increases dramatically. This problem is particularly acute during periods of UEG curtailment, or economic fuel switching by UEG customers.

152. When UEG rates rise sharply due to curtailment or fuel switching, the impact on cogenerators is greatly reduced through the availability to cogenerators of the otherwise applicable commercial or industrial rate.

153. We are not persuaded that the problem of variations in cogenerator gas rates due to changes in the average UEG rate is particularly significant.

154. Setting the cogeneration rate on the basis of total UEG gas and oil throughput would guarantee that the cogeneration rate would be below the UEG rate and would result in changes in the cogeneration rate completely unrelated to changes in the average UEG gas rate.

155. There is no justification for charging less than cost based rates for EOR customers in the absence of such a special contract.

156. Proposals to (1) use recorded UEG throughput instead of forecast throughput for determining the UEG demand charge; (2) to replace the two tier UEG rate design with a single volumetric rate;

and (3) to increase the percentage of return on equity and tax costs allocated to the volumetric charge from the present 25% to 100% would change the allocation of risk associated with UEG throughput and would put SoCal at increased risk.

157. SDG&E UEG fuel switching is likely to occur only during the peak winter months when we also forecast UEG curtailment that will equal or exceed economic fuel switching.

158. The findings, conclusions, and policy reasons supporting our decision to deny SoCal's request to amortize the balance in its CSA and to abolish the account apply equally to SDG&E.

159. The findings, conclusions, and policy reasons supporting our decision to reject the recommendation to base SoCal's cogeneration transportation rate on total UEG oil and gas throughput apply equally to SDG&E.

160. The carrying costs of gas in storage are seasonal costs.

<u>Conclusions of Law</u>

1. The issues raised by Long Beach concerning SoCal's tariff provisions governing curtailment are beyond the scope of this ACAP proceeding.

2. The reasonableness of any purchases of Elk Hills gas above the core WACOG should be considered in SoCal's annual reasonableness review and not in this ACAP.

3. Elk Hills purchases do not meet the definition of transition costs established in D.87-12-039 and should not receive transition cost treatment on that basis.

4. Whether the take-or-pay costs which SoCal seeks to recover were reasonably incurred is not at issue in this proceeding.

5. Under the Commission's regulatory program for gas utilities, reasonableness must be considered in annual utility reasonableness review proceedings.

6. The ALJ was correct in striking SoCal testimony on the reasonableness review proceedings.

7. The only take-or-pay issues properly before the Commission in this ACAP proceeding are issues related to the allocation of costs.

8. Utility regulation is a substitute for free market competition, and although regulation has relieved utilities of substantial economic and competitive risks, it was never intended to relieve utilities of all of the risks inherent in competitive or regulated markets.

9. Risk is recognized in the rate setting process.

10. Regulators are required by law to set rates so as to provide utilities with a reasonable opportunity to earn a return commensurate with returns on investments <u>with similar risks</u>.

11. The law does not guarantee that utilities will earn the return authorized, and certainly does not require utility ratepayers to shoulder 100 percent of the economic burden of unforeseen events.

12. The manner in which utility rates are set generally contemplates that unforeseen events will, from time to time affect company earnings, and will sometimes cause earned return to fall below what was authorized.

13. The rates of return granted utilities in each general rate case implicitly include allowances to compensate utilities for economic and regulatory risks, including unforeseen risks.

14. 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.

15. FERC's decision approving take-or-pay costs explicitly provides for, and encourages, an equitable sharing of costs between local distribution companies, such as SoCal, and their customers.

16. The FERC has not prescribed the methods by which this Commission should allocate SoCal's take-or-pay costs.

17. There is no absolute entitlement to the collection of balances recorded in balancing on tracking accounts.

18. Recovery of take-or-pay costs booked to the Core and Noncore Fixed Cost balancing accounts was explicitly made subject to future regulatory review by the Commission in D.87-12-039.

19. We have not considered or determined the reasonableness of any take-or-pay costs SoCal may pass through to ratepayers under this decision.

20. The options for direct billed take-or-pay recovery that DRA recommended will provide SoCal with a reasonable opportunity to recover take-or-pay costs and strikes a fair balance in allocating risks and costs between SoCal ratepayers and shareholders.

21. DRA's recommendation for allocation of direct billed take-or-pay costs is reasonable, equitable, and will be adopted.

22. No undercollections will be forecast in either the El Paso or Transwestern Account 191.

23. SoCal shall hold Chevron/Southland credits in an interest bearing accounts for offset against possible future Account 191 billings.

24. SoCal shall hold Mid-Louisiana/RFX refunds in an interest bearing account for use as an offset against possible Account 191 direct billings.

25. We find no evidence of prior Commission intent to include litigation and settlement costs in the CCA balancing account.

26. Although in D.82-02-135 the Commission did say that all expenses and revenues associated with the WFCP would be accounted for in the CCA, we interpret this to mean that the Commission considered the categories and accounts listed on p. 208 of the decision to encompass all of the costs that it considered properly associated with the WFCP program.

27. Since litigation and settlement costs are not included in the accounts listed in D.82-02-135, we concluded that these costs were intended by the Commission to continue to be recovered in the

unusual manner, i.e., on a forecast basis through the allowance for administrative and general expenses included in base rates.

28. In implementing our new regulatory program, there was never any intent to change our existing practice of using oil revenues to offset other expenses.

29. Since, the treatment of oil revenues is a question of how the regulatory changes made last year should be interpreted, and not whether changes should be adopted now and applied retroactively, no retroactive ratemaking problem is involved.

30. The accounting stipulation adopted by the Commission to implement the Commission's new gas program should be interpreted to require that oil revenues, which were subject to balancing account treatment under the CAM procedure, be credited to the GFCA under the new procedure.

31. As required by D.89-02-082, storage banking revenue shall be credited to reduce the storage related costs allocated to noncore customers.

32. Forecast interutility revenue for service by SoCal to PG&E of $0.8 million based upon forecast curtailment of 2,933 Mdth and throughput of 8,700 Mdth is reasonable and will be adopted.

33. Exchange volume and revenue forecasts of $8.5 million and 29,427 Mdth, respectively, based upon 488 Mdth of forecast curtailment for this service are reasonable and will be adopted.

34. SoCal has excluded marketing related costs from its estimate of brokerage costs contrary to clear Commission policy.

35. Pending completion of a new study of brokerage costs which includes related costs, it is reasonable to set an interim brokerage fee based upon brokerage costs of $3,878,000, which includes $2,378,000 for procurement related costs, and $1,500,000 for marketing related costs.

36. It is reasonable to use the ratio implicit in DRA's recommended brokerage cost estimate (61% procurement and 39% marketing) in allocating the brokerage related costs. It is

reasonable to allocate the procurement portion to noncore transportation rates. It is reasonable to allocate 98.133% of the marketing related costs to reduce core rates, and 1.667% to reduce noncore transportation rates.

37. SoCal's estimate of brokerage costs is based upon outdated costs information, and is clearly incomplete.

38. Although it is not entirely clear whether DRA has captured all costs in the guidelines specified in D.89-09-094, DRA's overall estimate of $3,878,000 in brokerage related costs is a reasonable estimate for the ACAP period.

39. It is reasonable to deny SoCal's request to amortize the balance in its CSA, and to abolish the account.

40. Authorizing costs to be booked to a tracking account is no guarantee of future recovery.

41. Revenue requirement associated with company use and LUAF gas should be adjusted to reflect the effects of forecast curtailments on throughput.

42. PU Code § 739.6 limits Commission discretion to modify its existing methodology for allocating gas company costs among the various customer classes.

43. It is the clear intent of PU Code § 739.7 to maintain the Commission's existing cost allocation practices, at least until January 1991. The Commission is, however, extended latitude to modify existing practices in limited circumstances to remedy customer hardships and inequities provided that they can be eliminated without, on balance, adversely affecting residential ratepayers.

44. Because of the restrictions contained in PU Code § 739.6, it is reasonable to maintain existing cost allocation policies, unless we find a compelling reason for change that can be made consistent with the requirements of the statute.

45. It is reasonable to allocate PGA over and undercollections to both core and core-elect customers.

46. It is reasonable to allocate EOR overcollections on a forecast basis, on an equal percentage of "fixed cost" revenues.

47. It is reasonable to allocate the difference between the revenues cogenerators will pay (paying the average UEG rate) and the higher cost of serving cogeneration customers to the UEG and cogeneration classes.

48. It is reasonable to allocate reasonably incurred take-or-pay costs be recovered under this decision to all customers without reducing the percentage allocated to UEG customers.

49. It would not be appropriate to make interim rate changes on the basis of SoCal's A&G or LUAF cost studies prior to determining their validity.

50. Until a showing is made concerning the long-term contracts signed by Long Beach and SDG&E and the revenue shortfall experienced as a result of such contracts, it is reasonable to allocate a portion of SoCal's long-term contract shortfall to wholesale customers.

51. Company use gas is currently allocated to customers on the basis of forecasted throughput, and it is reasonable to continue this allocation policy.

52. It would be inequitable within the meaning of PU Code § 739.6 to allocate the carrying cost of gas to wholesale customers that store their own gas.

53. Wholesale customers that store their own gas can be given a credit for the carrying cost of gas they store without adversely affecting residential ratepayers.

54. It is reasonable to give wholesale customers a credit for gas they store on their own account during the ACAP period.

55. SoCal's proposed methodology of allocating the costs of SoCal's transmission facilities to SDG&E is closer to the method previously used by the Commission to allocate the cost of these facilities, is reasonable, and will be adopted.

56. SDG&E's proposal to change the manner in which various balancing account balances are allocated from SoCal to SDG&E is inconsistent with prior Commission decisions which indicate our intent to treat wholesale core and noncore load in the same manner.

57. It is reasonable to continue our existing method of allocating PITCO and POPCO demand charges.

58. In the context of residential gas rates, the policy objectives of (1) maintaining or increasing customer control over monthly utility bills through usage sensitive rate design, (2) maintaining an appropriate balance of risk between ratepayers and utilities under our new gas program, and (3) maintaining residential conservation incentives outweigh any benefits that might be achieved by increasing the customer charge to more closely match the fixed costs of providing residential service.

59. Due to concerns about the effects of rate design changes on residential customers' bills, we will reduce SoCal's winter season baseline allowances consistent with our previously adopted three-phase program.

60. In order to moderate customer impacts while still moving rapidly to reduce the differential between residential Tier I and Tier II rates, it is reasonable to increase both SoCal's Tier I and Tier II.

61. The differences in the end use priority and alternate fuel capability of customers in the P2B and Other Industrial classes justifies continuation of separate P2B and other industrial rate schedules.

62. DRA's proposed seasonal definitions for seasonally differentiated non-residential rates are reasonable and will be adopted.

63. We find no compelling reason to modify the existing demand/volumetric rate structure for commercial and industrial customers.

64. Changes in the method of calculating QF energy payments beyond the scope of this ACAP proceeding.

65. Until a more compelling case for modification of our cogeneration rate setting methodology is made, it is reasonable to set the cogeneration transportation rate on a lagged-recorded basis.

66. In D.87-12-039, we previously determined that the average UEG transportation rate used in setting the cogeneration rate should include the transmission charges for igniter fuel.

67. In the absence of a special contract, it is reasonable to require that EOR customers be required to pay a rate equivalent to the industrial default.

68. No compelling reason has been offered to change the structure of the UEG rate design.

69. It is reasonable to apply the core transportation rate to UEG igniter fuel in this proceeding.

70. PU Code § 739.5 requires that the master-meter discount be based upon the costs to master-meter customers of providing submeter service.

71. WMA has failed to meet its burden of proof concerning the costs incurred by master-meter customers in providing submeter service in SoCal's service territory.

72. Until a more complete record is developed on the arguments Long Beach has raised concerning the alleged anti-competitive effect of SoCal's proposed wholesale volumetric rate, it is reasonable to set the wholesale volumetric rate charged Long Beach at the volume weighted average of the UEG Tier I and Tier II volumetric rates.

73. DRA's forecasts of SDG&E residential, core commercial, and noncore customer classes throughput are reasonable and will be adopted.

74. 212.4 MMth is a reasonable forecast of SDG&E cogeneration throughput and will be adopted.

75. A UEG throughput forecast for SDG&E of 305 MMth based upon SDG&E UEG demand of 384 MMth and curtailment of 79 MMth is reasonable and will be adopted.

76. $2.19/MMBtu at the border is a reasonable forecast of SDG&E's core and noncore WACOG and will be adopted.

77. The policy reasons, findings of fact, and conclusions of law supporting our decision to adopt DRA's approach to the allocation of take-or-pay costs direct billed to SoCal apply equally to SDG&E.

78. Extending to SDG&E the options for direct billed take-or-pay cost recovery that DRA recommended for SoCal will provide SDG&E with a reasonable opportunity to recover take-or-pay costs and strikes a fair balance in allocating risks and costs between SDG&E's ratepayers and shareholders.

79. It is reasonable to deny SDG&E's request to amortize the balance in its CSA, and to abolish SDG&E's CSA.

80. We find no reason to deviate from our established policy of allocating the carrying costs of gas in storage to the D2 demand charge in this decision.

81. It is reasonable to reduce the seasonal differential in core commercial rates by one half in order to moderate the impact of wide seasonal variations in core commercial bills.

82. The findings, conclusions, and policy reasons supporting our decision to continue to base SoCal's cogeneration transportation rate on the basis of the lagged recorded average UEG rate apply equally to SDG&E.

83. It is reasonable to continue to set SDG&E's cogeneration transportation rate on the basis of the lagged recorded average UEG rate.

84. We find no reason to deviate from our established policy of including igniter fuel in the average UEG rate used to set the cogeneration transportation rate.

85. It is reasonable to increase SDG&E's average rate for liquified natural gas (LNG) service to the Borrego area by 10%.

86. We find no need to require utilities to provide any additional information in ACAP proceedings concerning gas utility portfolio construction or management at this time.

87. Suggested changes in operational guidelines for gas utilities are beyond the scope of ACAP proceedings and should be addressed in a separate proceeding initiated for the purpose of reviewing the relevant tariff rules.

88. The updated information provided by SoCal and SDG&E is of a noncontroversial and readily verifiable nature and as a consequence, we will receive the updates in evidence.

89. TURN has demonstrated significant financial hardship within the meaning of Rules 76.52(f), 75.53, and 76.54(a) as revised in D.85-06-126, and is found eligible for compensation.

O R D E R

IT IS ORDERED that:

1. Take-or-pay payments previously made by Southern California Gas Company (SoCal) to Pacific Offshore Production Company and reflected in SoCal's Cost Adjustment Mechanism account, shall be adjusted to reflect the actual payments authorized by the Federal Energy Regulatory Commission (FERC).

2. Within 20 days of the date of issuance of this proposed decision, SoCal shall file comments indicating the rate treatment it selects for recovery of direct billed take-or-pay costs and proposed rate changes to implement consistent with the company's selection of the ratemaking options provided herein.

3. SoCal shall hold Chevron/Southland credits in an interest bearing accounts for offset against possible future Account 191 billings.

4. SoCal shall hold Mid-Louisiana/RFX refunds in an interest bearing account for use as an offset against possible Account 191 direct billings.

5. As required by D.89-02-082, storage banking reservation fees shall be credited to reduce the storage related costs allocated to noncore customers.

6. SoCal shall prepare a new cost study of brokerage related costs, consistent with the guidelines contained in D.89-09-094, for consideration in SoCal's next ACAP.

7. Wholesale customers shall be entitled to claim a credit for the cost of gas stored by the wholesale customer during the ACAP period and may claim this credit in SoCal's next ACAP proceeding.

8. The updated information provided by SoCal and San Diego Gas and Electric Company (SDG&E) is of a noncontroversial and readily verifiable nature and as a consequence, the updates are in evidence.

9. The requests of Toward Utility Rate Normalization and Southern California Utility Power Pool and the Imperial Irrigation District to require additional updated information from SoCal are denied.

10. The motion of Southern California Edison Company requesting interim rate relief is denied.

11. SoCal's motion to strike portions of the opening brief of Long Beach is denied.

12. This proceeding is continued to a subsequent phase to consider the following issues which have been deferred: (1) SoCals' Administrative and General and Lost and Unaccounted for gas cost allocation studies, and changes in cost allocations resulting from these studies; (2) whether cogenerators that do not meet FERC efficiency standards set forth in Section 292.205 of Title 18 of the Code of Federal Regulations should be entitled to UEG-parity gas rates under PU Code § 454.4; and (3) whether the

cogeneration gas limitation should be calculated on the basis of incremental energy rates or incremental heat rates.

13. Concurrent with the issuance of this decision, Southern California Gas Company (SoCal) shall file, in accordance with General Order (GO) 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. Tariff changes will be effective February 1, 1989.

14. Concurrent with the issuance of this decision, San Diego Gas and Electric Company (SDG&E) shall file, in accordance with GO 96-A, tariff changes which implement the rate changes adopted in this proceeding, and which are shown in Appendix E to this decision, using the revenue requirement presented in Appendix D. Tariff changes will be effective February 1, 1989.

This order is effective today.

Dated JAN 9 1990, at San Francisco, California.

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

Commissioner Stanley W. Hulett, being necessarily absent, did not participate.

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

Wesley Franklin

WESLEY FRANKLIN, Acting Executive Director

APPENDIX A
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List of Appearances

Applicant in A.89-04-021: Glen J. Sullivan, Mark P. Minich, Jeffrey E. Jackson, Attorneys at Law, and L. P. Lorenz, for Southern California Gas Company.

Applicant in A.89-05-006 and Interested Parties in A.89-04-021: Barton M. Myerson, David R. Clark, and Judy Anderson, Attorneys at Law, for San Diego Gas & Electric Company.

Interested Parties: Michael P. Alcantar, Attorney at Law, for Cogenerators of Southern California; Richard Owen Baish, Michael D. Ferguson, and Randolph L. Wu, Attorneys at Law, for El Paso Natural Gas Company; Tom Beach, for Crossborder Services; Matthew V. Brady, Attorney at Law, for the State of California; Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for the California Cogeneration Council; W. E. Cameron, for the City of Glendale; John Dunn, for Salmon Resource Ltd.; Richard K. Durant, Frank J. Cooley, Michael Gonzales, Carol B. Henningson, Julie A. Miller, and Robert S. Robinson, Attorneys at Law, for Southern California Edison Company; Karen Edson, for KKE & Associates; Ronald V. Stassi and Frederic C. Fletcher, for City of Burbank; Michel Peter Florio, and Joel Singer, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobile Home Association; Steven M. Harris, for Transwestern/ Enron; David T. Helsby, for R. W. Beck & Associates; Robert Hohne Associates, by Robert J. Hohne, for Robert J. Hohne; Harry W. Long, Jr. and Mark Huffman, Attorneys at Law, for Pacific Gas and Electric Company; Bill Marcus, for JBS Energy; Squire, Sanders & Dempsey, by Keith R. McCrea and Michael Mishkin, Attorneys at Law, for California Industrial Group and California League of Food Processors; Wayne Meek and Kathi Robertson, for Simpson Paper Company; Leamon W. Murphy, for the Imperial Irrigation District; Jones, Day, Reavis & Pogue, by Norman A. Pedersen, Attorney at Law, for Southern California Utility Power Pool; Robert L. Pettinato, for the Los Angeles Department of Water & Power; David Plumb, for the City of Pasadena; Patrick J. Power, Attorney at Law, for the City of Long Beach; Paul Premo, for Chevron USA; John D. Quinley, for Cogeneration Service Bureau; Dr. Andrew Safir, for Recon Research Corporation; Donald W. Schoenbeck, for RCS, Inc.; Skaff & Anderson, by Andrew Skaff, Attorney at Law, for Natural Gas Clearinghouse; Shelley Ilene Smith, Asst. City Attorney, and Preston A. Mike, for the City of Los Angeles; Armour, St. John, Wilcox, Goodin & Schlotz, by James D. Squeri and Barbara Snider, Attorneys at Law, for Kelco, Division of Merck; Nancy Thompson, for Barakat, Howard & Chamberlin; William W. Wade, for Spectrum Economics; Natalie Walsh, for the California Energy Commission; Larry Watkins, for South Coast Air Quality Management District

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(SCAQMD); Robert K. Weatherwax, for Sierra Energy & Risk Assessment; Robert B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates; Harry K. Winters, for Regents, University of California; Michael Rieke, for Gas Daily Newsletter; Patrick McDonnell, for Agland Energy Services; John W. Witt, City Attorney, by William S. Shaffran and Leslie Girard, Deputy City Attorneys, for the City of San Diego; Brian Sibold, for Energy Factors; Barkovich and Yap, by Barbara Barkovich, for California Large Energy Consumers Association; Luce, Forward, Hamilton & Scripps, by John W. Leslie and Kathryn Fehrman, Attorneys at Law, for Salmon Resources, Ltd., and Mock Resources, Inc.; Graham and James, by Peter W. Hanschen, and Martin A. Mattes, Attorneys at Law, for Trigen Resources Corporation; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr, Attorney at Law, for Industrial Users; and Lindsay, Hart, by Paul J. Kaufman, Attorney at Law, for himself.

Division of Ratepayer Advocates: Patrick L. Gileau, John S. Wong, Attorneys at Law, James Boothe, and Robert Mark Pocta.

Commission Advisory and Compliance Division: Karen Shea and John L. Dutcher.

(END OF APPENDIX A)

TABLE 1

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED GAS DEMAND & DELIVERIES

Forecast Period: October 1, 1989 to September 30, 1990

THROUGHPUT TYPE	GAS DEMAND (Mdth)	
Residential	303,093.0	
Commercial Core	76,448.0	
Commercial Non-Core	20,000.0	
Industrial Core	23,422.0	
ARIMA forecast	16,000.0	
Industrial Non-Core	70,000.0	
Retail UEG	188,386.0	
Regular Cogeneration	72,967.0	
EOR Cogeneration	121,984.0	
EOR Steamflood	38,714.0	
Company use	8,032.8	
Unaccounted for	11,182.5	
Long Beach - wholesale	28,523.0	
San Diego - wholesale	109,128.8	
Discount adjustment	5,678.3	
Total Sales and Transport	1,093,559.4	Mdth
Exchange	29,915.0	
Interutility transport	11,633.0	
TOTAL GAS DEMAND	1,135,107.4	Mdth
System capacity	1,000,587.2	
Supplies from PG&E	71,758.2	
AVAILABLE SUPPLIES	1,072,345.4	Mdth
AVERAGE YEAR CURTAILMENTS	62,762.0	Mdth

TABLE 2

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND by CUSTOMER CLASS

Forecast Period: October 1, 1989 to September 30, 1990

SCHEDULE AND CATEGORY		PRIO-RITY	UNADJUSTED DEMAND (Mdth)	DISCOUNT ADJUSTMENT (Mdth)	CURT-AILMENT (Mdth)	DISCOUNT ADJUSTED DEMAND (Mdth)
Residential demand			303,093.0			303,093.0
Commercial	GN-10C	P-1	72,954.3			72,954.3
Commercial	GN-20C	P-2A	3,340.8			3,340.8
Commercial	GN-20T	P-2A	152.9			152.9
Commercial	GN-20C	P-2B	18.0			18.0
Commercial	GN-30N	P-2B	1,352.0	113.9		1,465.9
Commercial	GN-30T	P-2B	38.0	3.2		41.2
Commercial	GN-30N	P-3A	3,407.6			3,407.6
Commercial	GN-30T	P-3A	1,014.2			1,014.2
Commercial	GN-50C	P-3A	831.8			831.8
Commercial	GN-50N	P-3A	4,210.2			4,210.2
Commercial	GN-50T	P-3A	3,531.6			3,531.6
Commercial	GN-50T(L)	P-3A	4,115.3			4,115.3
Commercial	GN-30C	P-3B	874.0			874.0
Commercial	GN-30N	P-3B	12,478.0	787.5		13,265.5
Commercial	GN-30T	P-3B	860.0	54.3		914.3
Commercial	GN-30C	P-4	304.0			304.0
Commercial	GN-30N	P-4	4,038.0	254.8		4,292.8
Commercial	GN-30T	P-4	38.0	2.4		40.4
Total Commercial demand			113,558.8	1,216.1	0.0	114,774.9
Industrial	GN-10C	P-1	23,398.6			23,398.6
Industrial	GN-20C	P-2A	14,833.6			14,833.6
Industrial	GN-20T	P-2A	1,166.4			1,166.4
Industrial	GN-20C	P-2B	133.0			133.0
Industrial	GN-20C	P-2B	119.0			119.0
Industrial	GN-20T	P-2B	23.4			23.4
Industrial	GN-30N	P-2B	9,730.0	819.9		10,549.9
Industrial	GN-30T	P-2B	2,135.0	179.9		2,314.9
Industrial	GN-30T(L)	P-2B	35.0			35.0
Industrial	GN-30N	P-3A	3,590.0			3,590.0
Industrial	GN-30T	P-3A	10,762.6			10,762.6
Industrial	GN-30T(L)	P-3A	802.6			802.6
Industrial	GN-50C	P-3A	145.9			145.9
Industrial	GN-50N	P-3A	4,246.7			4,246.7
Industrial	GN-50T	P-3A	27,121.8			27,121.8
Industrial	GN-50T(L)	P-3A	9,186.5			9,186.5
EOR Cogen	GN-40N	P-3A	7,300.0			7,300.0
EOR Cogen	GN-40T	P-3A	1,360.0			1,360.0
EOR Cogen	GN-40L	P-3A	113,324.0			113,324.0

TABLE 2 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND by CUSTOMER CLASS

Forecast Period: October 1, 1989 to September 30, 1990

SCHEDULE AND CATEGORY		PRIORITY	UNADJUSTED DEMAND (Mdth)	DISCOUNT ADJUSTMENT (Mdth)	CURTAILMENT (Mdth)	DISCOUNT ADJUSTED DEMAND (Mdth)
Industrial	GN-30C	P-3B	819.0			819.0
Industrial	GN-30N	P-3B	28,175.0	1,778.1		29,953.1
Industrial	GN-30T	P-3B	18,620.0	1,175.1		19,795.1
Industrial	GN-30T(L)	P-3B	3,227.0			3,227.0
Industrial	GN-30N	P-4	3,640.0	229.7		3,869.7
Industrial	GN-30T	P-4	2,898.0	182.9		3,080.9
Industrial	GN-30T(L)	P-4	469.0			469.0
EOR Steam	GN-40N	P-5	3,650.0		(921.5)	2,728.5
EOR Steam	GN-40T	P-5	5,285.0		(1,334.3)	3,950.7
EOR Steam	GN-40T(L)	P-5	29,779.0		(7,518.1)	22,260.9
Total Industrial demand			325,976.2	4,365.6	(9,773.8)	320,568.0
UEG sales	GN-60C	P-2A	736.0			736.0
UEG trans	GN-60T	P-2A	2,064.0			2,064.0
UEG Noncore	GN-60N	P-3	33,671.8			33,671.8
UEG S-Term	GN-60T	P-3	9,792.8			9,792.8
UEG L-Term	GN-60T(L)	P-3	0.0			0.0
UEG Noncore	GN-60N	P-5	105,809.1		(26,712.8)	79,096.3
UEG S-Term	GN-60T	P-5	36,312.4		(9,167.5)	27,144.9
UEG L-Term	GN-60N(L)	P-5	0.0		0.0	0.0
Total UEG demand			188,386.0	0.0	(35,880.3)	152,505.7
Exchange w/other util		P-1	2,128.0			2,128.0
Onshore Cal. exch.		P-1	185.0			185.0
Offshore P.Point exch		P-1	345.0			345.0
Onshore Cal. exch.		P-2A	1,147.0			1,147.0
Offshore P.Point exch		P-2A	1,791.0			1,791.0
Onshore Cal. exch.		P-2B	553.0			553.0
Offshore P.Point exch		P-2B	906.0			906.0
Onshore Cal. exch.		P-3A	5,002.0			5,002.0
Offshore P.Point exch		P-3A	6,115.0			6,115.0
Onshore Cal. exch.		P-3B	5,643.0			5,643.0
Offshore P.Point exch		P-3B	1,794.0			1,794.0
Onshore Cal. exch.		P-4	2,244.0			2,244.0
Offshore P.Point exch		P-4	127.0			127.0
Onshore Cal. exch.		P-5	627.0		(158.3)	468.7
Offshore P.Point exch		P-5	1,308.0		(330.2)	977.8
Total Exchange demand			29,915.0	0.0	(488.5)	29,426.5

TABLE 2 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND by CUSTOMER CLASS

Forecast Period: October 1, 1989 to September 30, 1990

SCHEDULE AND CATEGORY	PRIORITY	UNADJUSTED DEMAND (Mdth)	DISCOUNT ADJUSTMENT (Mdth)	CURTAILMENT (Mdth)	DISCOUNT ADJUSTED DEMAND (Mdth)
Fuel use - injection	P-1	1,817.7	9.1	(101.0)	1,725.8
Fuel use - mainline	P-1	5,485.6	27.6	(304.8)	5,208.4
Misc. company use	P-1	656.3	3.3	(36.5)	623.2
Misc. company use	P-2A	73.2	0.4	(4.1)	69.5
Total company use		8,032.8	40.4	(446.4)	7,626.8
Unaccounted for	P-1	11,182.5	56.2	(621.4)	10,617.3
TOTAL RETAIL DEMAND		980,144.3	5,678.3	(47,210.4)	938,612.2
LBeach sales S-T TRN	P-1	9,016.0			9,016.0
LBeach co use S-T TRN	P-1	12.0			12.0
LBeach unacct S-T TRN	P-1	330.0			330.0
Less: own supply	P-1	4,883.0			4,883.0
LBeach sales S-T TRN	P-2A	753.0			753.0
LBeach S-T TRN	P-2B	110.0			110.0
LBeach S-T TRN	P-3A	24.0			24.0
LBeach reg S-T TRN	P-3B	3,712.0			3,712.0
LBeach S-T TRN	P-4	1,162.0			1,162.0
LBeach UEG S-T	P-5	18,287.0		(4,616.8)	13,670.2
Total Long Beach		28,523.0	0.0	(4,616.8)	23,906.2
SDG&E sales S-T TRN	P-1	42,396.4			42,396.4
SDG&E co use S-T TRN	P-1	140.3		(10.3)	130.0
SDG&E unacct S-T TRN	P-1	1,080.5		(79.2)	1,001.3
SDG&E sales S-T TRN	P-2A	794.9			794.9
SDG&E IGN S-T TRN	P-2A	163.0			163.0
SDG&E S-T TRN	P-3B	8,744.2			8,744.2
SDG&E S-T TRN	P-3A	17,535.5			17,535.5
SDG&E UEG S-T TRN	P-5	31,325.0		(7,908.4)	23,416.6
SDG&E UEG S-T TRN	P-3B	6,949.0			6,949.0
Total San Diego		109,128.8	0.0	(7,997.8)	101,130.9
TOTAL WHOLESALE DEMAND		137,651.8	0.0	(12,614.6)	125,037.1
INTERUTILTY DEMAND	P-5	11,633.0	0.0	(2,936.9)	8,696.1
TOTAL DEMAND		1,129,429.1	5,678.3	(62,762.0)	1,072,345.4

TABLE 3

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND by PRIORITY RANKING

Forecast Period: October 1, 1989 to September 30, 1990

PRIORITY	UNADJUSTED DEMAND (Mdth)	DISCOUNT ADJUSTMENT (Mdth)	CURT-AILMENT (Mdth)	DISCOUNT ADJUSTED DEMAND (Mdth)
P-1	469,338.2	96.2	(1,153.2)	468,281.2
P-2A	27,015.8	0.4	(4.1)	27,012.1
P-2B	15,152.4	1,117.0		25,013.6
P-3	43,464.6	0.0		43,464.6
P-3A	230,576.5	0.0		247,044.1
P-3B	84,946.2	3,794.9		79,996.9
P-4	14,920.0	669.8		15,589.8
P-5	244,015.4	0.0	(61,604.7)	165,943.1
TOTAL DEMAND	1,129,429.1	5,678.3	(62,762.0)	1,072,345.4

Note: P-1 and P-2A curtailments reflect the reduction in "company use and unaccounted for" gas as a consequence of adopted P-5 curtailments.

TABLE 4

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND by PORTFOLIO CLASS

Forecast Period: October 1, 1989 to September 30, 1990

		PRIORITY	DISCOUNT ADJ. DEMAND (Mdth)	
CORE & CORE-ELECT PORTFOLIO DEMAND				
Residential demand				303,093.0
Commercial	GN-10C	P-1	72,954.3	
Industrial	GN-10C	P-1	23,398.6	
Non-Residential demand				96,352.9
Commercial	GN-20C	P-2A	3,340.8	
Industrial	GN-20C	P-2A	14,833.6	
Commercial	GN-20C	P-2B	18.0	
Industrial	GN-20C	P-2B	133.0	
Non-Residential demand				18,325.4
Industrial	GN-20C	P-2B	119.0	
Commercial	GN-30C	P-3B	874.0	
Industrial	GN-30C	P-3B	819.0	
Commercial	GN-30C	P-4	304.0	
Regular Commercial & Industrial demand				2,116.0
UEG sales	GN-60C	P-2A	736.0	
UEG trans	GN-60C	P-2A	2,064.0	
Retail UEG demand				2,800.0
Commercial	GN-50C	P-3A	831.8	
Industrial	GN-50C	P-3A	145.9	
Regular Cogeneration demand				977.8
Subtotal				423,665.0
Company use .				5,167.4
Unaccounted for				7,193.5
TOTAL CORE & CORE-ELECT PORTFOLIO DEMAND				436,025.9
NON-CORE PORTFOLIO DEMAND				
Commercial	GN-30N	P-2B	1,465.9	
Industrial	GN-30N	P-2B	10,549.9	

TABLE 4 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND by PORTFOLIO CLASS

Forecast Period: October 1, 1989 to September 30, 1990

		PRIORITY	DISCOUNT ADJ. DEMAND (Mdth)	
Commercial	GN-30N	P-3B	13,265.5	
Industrial	GN-30N	P-3B	29,953.1	
Commercial	GN-30N	P-4	4,292.8	
Industrial	GN-30N	P-4	3,869.7	
Regular Commercial & Industrial demand				63,397.0
UEG Noncore	GN-60N	P-3	33,671.8	
UEG Noncore	GN-60N	P-5	79,096.3	
Retail UEG demand				112,768.1
Commercial	GN-30N	P-3A	3,407.6	
Commercial	GN-50N	P-3A	4,210.2	
Industrial	GN-30N	P-3A	3,590.0	
Industrial	GN-50N	P-3A	4,246.7	
Regular Cogeneration demand				15,454.4
EOR - Cogeneration		P-3A		7,300.0
EOR - Steamflood		P-5		2,728.5
Subtotal				201,647.9
Company use				2,459.5
Unaccounted for				3,423.8
TOTAL NON-CORE PORTFOLIO DEMAND				207,531.2
SHORT-TERM TRANSPORT DEMAND				
Commercial	GN-20T	P-2A	152.9	
Industrial	GN-20T	P-2A	1,166.4	
Industrial	GN-20T	P-2B	23.4	
Non-Residential demand				1,342.7
Industrial	GN-30T	P-2B	2,314.9	
Commercial	GN-30T	P-2B	41.2	
Commercial	GN-30T	P-3B	914.3	
Industrial	GN-30T	P-3B	19,795.1	
Commercial	GN-30T	P-4	40.4	
Industrial	GN-30T	P-4	3,080.9	
Regular Commercial & Industrial demand				26,186.8

TABLE 4 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND by PORTFOLIO CLASS

Forecast Period: October 1, 1989 to September 30, 1990

	PRIORITY	DISCOUNT ADJ.	DEMAND (Mdth)
UEG S-Term GN-60T	P-3	9,792.8	
UEG S-Term GN-60T	P-5	27,144.9	
Retail UEG demand			36,937.6
Commercial GN-30T	P-3A	1,014.2	
Industrial GN-30T	P-3A	10,762.6	
Commercial GN-50T	P-3A	3,531.6	
Industrial GN-50T	P-3A	27,121.8	
Regular Cogeneration demand			42,430.3
EOR - Cogeneration	P-3A		1,360.0
EOR - Steamflood	P-5		3,950.7
SDG&E IGN S-T TRN	P-2A	163.0	
SDG&E UEG S-T TRN	P-5	23,416.6	
SDG&E UEG S-T TRN	P-3B	6,949.0	
SDG&E Wholesale UEG			30,528.6
SDG&E sales S-T TRN	P-1	42,396.4	
SDG&E sales S-T TRN	P-2A	794.9	
SDG&E S-T TRN	P-3B	8,744.2	
SDG&E S-T TRN	P-3A	17,535.5	
SDG&E Wholesale NON-UEG			69,471.0
SDG&E co use S-T TRN	P-1	130.0	
SDG&E unacct S-T TRN	P-1	1,001.3	
SDG&E company use & unaccounted for			1,131.3
LBeach UEG S-T	P-5		13,670.2
LBeach sales S-T TRN	P-1	9,016.0	
Less: own supply	P-1	4,883.0	
LBeach sales S-T TRN	P-2A	753.0	
LBeach S-T TRN	P-2B	110.0	
LBeach S-T TRN	P-3A	24.0	
LBeach reg S-T TRN	P-3B	3,712.0	
LBeach S-T TRN	P-4	1,162.0	
Long Beach Wholesale NON-UEG			9,894.0

TABLE 4 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND by PORTFOLIO CLASS

Forecast Period: October 1, 1989 to September 30, 1990

	PRIORITY		DISCOUNT ADJ. DEMAND (Mdth)
LBeach co use S-T TRN	P-1	12.0	
LBeach unacct S-T TRN	P-1	330.0	
Long Beach company use & unaccounted for			342.0
TOTAL SHORT-TERM TRANSPORT DEMAND			237,245.3
LONG-TERM TRANSPORT DEMAND			
Industrial GN-30T(L)	P-2B	35.0	
Industrial GN-30T(L)	P-3B	3,227.0	
Industrial GN-30T(L)	P-4	469.0	
Regular Commercial & Industrial demand			3,731.0
UEG trans GN-60T(L)	P-2A	0.0	
UEG L-Term GN-60T(L)	P-3	0.0	
UEG L-Term GN-60T(L)	P-5	0.0	
Retail UEG demand			0.0
Industrial GN-30T(L)	P-3A	802.6	
Commercial GN-50T(L)	P-3A	4,115.3	
Industrial GN-50T(L)	P-3A	9,186.5	
Regular Cogeneration demand			14,104.5
SDG&E IGN S-T TRN	P-2A	0.0	
SDG&E UEG S-T TRN	P-5	0.0	
SDG&E UEG S-T TRN	P-3B	0.0	
SDG&E Wholesale UEG			0.0
SDG&E sales S-T TRN	P-1	0.0	
SDG&E sales S-T TRN	P-2A	0.0	
SDG&E S-T TRN	P-3B	0.0	
SDG&E S-T TRN	P-3A	0.0	
SDG&E Wholesale NON-UEG			0.0
SDG&E co use S-T TRN	P-1	0.0	
SDG&E unacct S-T TRN	P-1	0.0	
SDG&E company use & unaccounted for			0.0

Note: Adopted demand for SDG&E is reflected in "short-term transport" as adopted in ALJ Malcolm's Proposed Decision in Order Instituting Rulemaking (OIR) 88-08-018.

TABLE 4 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND by PORTFOLIO CLASS

Forecast Period: October 1, 1989 to September 30, 1990

	PRIORITY	DISCOUNT	ADJ. DEMAND (Mdth)
EOR - Cogeneration	P-3A		113,324.0
EOR - Steamflood	P-5		22,260.9
TOTAL LONG-TERM TRANSPORT DEMAND			153,420.4
EXCHANGE DEMAND			
Exchange w/other util	P-1	2,128.0	
Onshore Cal. exch.	P-1	185.0	
Offshore P.Point exch	P-1	345.0	
Non-Residential demand			2,658.0
Onshore Cal. exch.	P-2A	1,147.0	
Offshore P.Point exch	P-2A	1,791.0	
Non-Residential demand			2,938.0
Onshore Cal. exch.	P-2B	553.0	
Offshore P.Point exch	P-2B	906.0	
Onshore Cal. exch.	P-3B	5,643.0	
Offshore P.Point exch	P-3B	1,794.0	
Onshore Cal. exch.	P-4	2,244.0	
Offshore P.Point exch	P-4	127.0	
Regular Commercial & Industrial demand			11,267.0
Onshore Cal. exch.	P-3A	5,002.0	
Offshore P.Point exch	P-3A	6,115.0	
Regular and EOR cogeneration demand			11,117.0
Onshore Cal. exch.	P-5	468.7	
Offshore P.Point exch	P-5	977.8	
EOR - Steamflood			1,446.5
TOTAL EXCHANGE DEMAND			29,426.5
INTERUTILITY TRANSPORT	P-5		8,696.1
TOTAL DEMAND			1,072,345.4

TABLE 5

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED COSTS

Forecast Period: October 1, 1989 to September 30, 1990

	VOLUMES (Mdth)	PRICE ($/dth)	COSTS (000's of $)	
Core & Core-Elect Supplies				
Elk Hills	10,361	2.3647	24,500.7	
Misc. California purchases	50,132	2.5044	125,550.6	
Direct purchases - SW USA	254,814	2.4210	616,905.9	
POPCO - Hondo Tiers 1 & 2	11,391	2.6500	30,186.2	
PITCO - Pan Alberta Tier 1	50,126	2.3340	116,993.2	
PITCO - Pan Alberta Tier 2	33,417	2.2367	74,743.8	
Federal Offshore	4,241	3.4178	14,495.0	
Core to Non-core Adj.	(38,622)	2.3647	(91,329.7)	
Short-term purchases	59,551	2.2215	132,292.0	
MPO Transition Cost Adj.			(14,719.2)	
Adj. Core/Core-elect pur	435,411			1,029,618.5
Core & Core-elect WACOG		2.3647		
Storage				
Storage Withdrawl	76,457	2.3647	180,798.3	
Storage Injection	(75,842)	2.3647	(179,344.0)	
Net storage	615			1,454.3
Non-Core Supplies				
Non-core purchases & WACOG	207,531	2.2014		456,863.4
Pipeline Demand Charges (fixed)				
El Paso			74,316.4	
Transwestern			73,661.0	
PITCO - Pan Alberta			105,504.0	
POPCO - Hondo			36,571.0	290,052.4
PIOC - Pitas Point	12,142			35,437.0

TABLE 5 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED COSTS

Forecast Period: October 1, 1989 to September 30, 1990

	VOLUMES (Mdth)	PRICE ($/dth)	COSTS (000's of $)	
Transition costs				
Direct bills:				
El Paso Liquids			54,250.0	
Take-or-Pay			30,668.0	
FERC Account 191			0.0	
Southland/Chevron			0.0	
Subtotal			84,918.0	
MPO Transition Cost Adj.			14,719.2	
Excess Purch. Gas Costs (carried over from 1988			0.0	99,637.2
Balancing/Tracking accounts				
Core Purchased Gas Account (CPGA)				152,890.0
Other Core accounts:				
Core Fixed Cost Account (CFCA)			5,215.7	
Core Implementation Account (CIA)			(39,043.5)	
Conservation Cost Adjustment (CCA)			(66,612.0)	
Enhanced Oil Recovery Account (EORA)			(25,119.0)	(125,558.8)
Non-Core accounts:				
Negotiated Revenue Stability Account (NRSA)			(1,856.0)	
Enhanced Oil Recovery Account (EORA)			(8,744.0)	
Noncore Implementation Account (NIA)			(41,911.0)	
Minimum Purchase Obligation (MPO)			6,764.0	
Pipeline Demand Charges (PDC)			(20,491.0)	
Noncore Transition Cost Account (NTCA)			2,639.0	
Cogeneration Shortfall Account (CSA)			0.0	
Carrying Cost of Storage			(2,219.0)	
Take-or-Pay			34,044.0	
Fixed Cost Acct. (NFCA) Marg. Shortfall			(1,811.9)	
Conservation Cost Adjustment (CCA)			(14,721.8)	(48,307.7)

TABLE 5 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED COSTS

Forecast Period: October 1, 1989 to September 30, 1990

	VOLUMES (Mdth)	PRICE ($/dth)	COSTS (000's of $)	
Company use and Unaccounted for				
Core Company Use	5,167	2.3120	11,947.2	
Core Unaccounted For	7,193	2.3120	16,631.7	
Total	12,361			28,578.9
Non-core Company Use	2,459	2.3120	5,686.4	
Non-core Unaccounted For	3,424	2.3120	7,916.0	
Total	5,883			13,602.4

TABLE 6

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED PORTFOLIO PRICES

Forecast Period: October 1, 1989 to September 30, 1990

	VOLUMES (Mdth)		COSTS (000's of $)
Core & Core-elect Portfolio			
Adj. Core & Core-elect purchases	435,411	1,029,618.5	
Net storage	615	1,454.3	
Core & Core-elect portfolio demand	436,026		1,031,072.7
Less: Company use & unaccounted for	12,361		28,578.9
Add: Core Purchased Gas Account (CPGA)			152,890.0
Subtotal			1,155,383.9
Add: FF&U at 1.864%			21,536.4
CORE & CORE-ELECT SALES	423,665		1,176,920.2
CORE & CORE-ELECT PORTFOLIO PRICE		$2.7779 /dth	
Non-Core Portfolio			
Non-core porfolio demand	207,531		456,863.4
Less: Company use & unaccounted for	5,883		13,602.4
Add: Pitas Point			35,437.0
Subtotal			478,697.9
Add: FF&U at 1.864%			8,922.9
Subtotal			487,620.9
Add: Brokerage fees			3,950.3
Less: Pitas Point			35,437.0
NON-CORE PORTFOLIO SALES	201,648		456,134.1
NON-CORE PORTFOLIO PRICE ($/dth)		$2.2620 /dth	

TABLE 7
SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED REVENUE REQUIREMENTS
Forecast Period: October 1, 1989 to September 30, 1990

		AMOUNTS (000's of $)
PROCUREMENT REVENUE REQUIREMENT		
Total Core Procurement Revenue	1,176,920.2	
Total Non-core Procurement Revenue	456,134.1	
TOTAL PROCUREMENT REVENUE REQUIREMENT		1,633,054.4
TRANSMISSION REVENUE REQUIREMENT		
Auth. gas margin (less brokerage fees) (To be adopted in A.88-12-047)		
Common distribution	343,937.0	
Demand related transmission	96,222.0	
Demand related storage	115,938.0	
Customer related	585,304.0	
Commodity related	10.0	
50% Administrative & General	110,381.0	
Brokerage fee adjustment	(2,456.3)	
		1,249,335.7
Pipeline demand charges	290,052.4	
Add: FF&U at 1.8640%	5,406.6	
		295,459.0
Transition costs	99,637.2	
Add: FF&U at 1.8640%	1,857.2	
		101,494.5
Net EOR adjustment		0.0
CAM balancing accounts		0.0
Long-term contract adjustment		0.0
CCA revenue requirement		23,910.0
Carrying cost of storage		6,458.2
Other Core Balancing/tracking accounts	(125,558.8)	
Non-Core Balancing/tracking accounts	(48,307.7)	
Add: FF&U at 1.8640%	(3,240.9)	
		(177,107.4)
Core Company use and unaccounted for gas	28,578.9	
Non-Core Company use and unaccounted for gas	13,602.4	
Add: FF&U at 1.8640%	786.3	
		42,967.6
Storage banking		(1,040.0)
Interutility transportation revenues		7,987.8
Exchange revenues		(8,702.4)
TOTAL TRANSMISSION REVENUE REQUIREMENT		1,540,762.9
NET REVENUE REQUIREMENT		3,173,817.3

(end of appendix b)

SOUTHERN CALIFORNIA GAS COMPANY
ALJ PROPOSED RATES AND REVENUES
CORE

CUSTOMER CLASS	THROUGH-PUT (MTh)	PRESENT RATE ($/Th)	PRESENT REVENUES (M$)	PROP RATE NON-GAS ($/Th)	PROP RATE GAS ($/Th)	PROP RATE TOTAL ($/Th)	PROP REVS NON-GAS (M$)	PROP REVS GAS (M$)	PROP REVS TOTAL (M$)	REVENUE % INC.
RESIDENTIAL	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Customer Charges/Dis.			147,095				146,866		146,866	-0.2%
Tier I	1,904,815	0.36675	698,591	0.10619	0.27048	0.37667	202,265	515,222	717,487	2.7%
Tier II	940,443	0.78095	734,439	0.48286	0.27048	0.75334	454,099	254,375	708,474	-3.5%
Residential Ave/Tot	2,845,258	0.55535	1,580,125	0.28231	0.27048	0.55279	803,231	769,596	1,572,827	-0.46%
LIRA										
Customer			9,556				8,317		8,317	-13.0%
Tier I	123,742	0.36675	45,382	0.04885	0.27048	0.31933	6,044	33,470	39,514	-12.9%
Tier II	61,094	0.78095	47,711	0.36817	0.27048	0.63866	22,493	16,525	39,018	-18.2%
LIRA SALES	184,835	0.55535	102,649	0.19939	0.27048	0.46987	36,854	49,995	86,849	-15.39%
CORE COMMERCIAL										
Customer Charges			26,181				26,181		26,181	
Summer										
Tier 1	453,274	0.47526	215,423	0.21075	0.27048	0.48123	241,329	122,603	218,131	
Tier 2	220,639	0.41026	90,519	0.15322	0.27048	0.42370	33,805	59,679	93,485	
Winter										
Tier 1	359,326	0.60823	218,553	0.38830	0.27048	0.65878	139,525	97,192	236,716	
Tier 2	126,841	0.45027	57,113	0.25589	0.27048	0.52638	32,458	34,308	66,766	
Commodity Ave/Total	1,160,080	0.50135	581,608	0.25974	0.27048	0.53022	301,315	313,783	615,098	
Commerc Sales Ave/Tot	1,160,080	0.52392	607,789	0.28231	0.27048	0.55279	327,496	313,783	641,279	5.5%
Transport Rate	13,190	0.31021	4,092	0.25974	0.00000	0.25974	3,426		3,426	-16.3%
CORE AVE/TRANSMISSION										
CORE AVE/TOT	4,203,363	0.54591	2,294,654	0.27859	0.26964	0.54822	1,171,007	1,135,374	2,304,381	0.4%

SOUTHERN CALIFORNIA GAS COMPANY
ALJ PROPOSED REVENUES AND ILLUSTRATIVE RATES
NONCORE

NONCORE CUSTOMER CLASS	ADJUSTED FORECAST DELIVERIES (MTH)	HISTORICAL BILLING DETERMINANTS (MTH/CUST)	PRESENT RATES EFFECTIVE 7/1/88 $/TH OR $/MO	PRESENT REVENUES EFFECTIVE 7/1/88 (M$)	PROPOSED RATE $/TH OR $/MO	PROPOSED REVENUES TOTAL NON-GAS (M$)	PROPOSED CHANGE ($/TH)	PROPOSED CHANGE (%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
PRIORITY P28								
Customer Charge		2,000	163.18	106	133.55	267	-0.00020	0.0%
Demand Charge D1	146,660	146,660	0.06179	9,062	0.02245	3,293	-0.03934	-63.7%
Demand Charge D2								
Summer	122,216	122,216	0.02221	2,714	0.01334	1,631	-0.00887	-39.9%
Winter	61,108	61,108	0.04357	2,662	0.03490	2,133	-0.00867	-19.9%
Volumetric Charge	146,660		0.04162	6,104	0.03859	5,659	-0.00303	-7.3%
TOT/AVE P28	146,660		0.14101	20,680	0.08852	12,982	-0.05249	-37.2%
INDUSTRIAL								
Customer Charge		7,747	483.45	900	227.75	1,764	-0.00027	0.0%
Demand Charge D1		959,840	0.06180	59,318	0.02298	22,060	-0.03882	-62.8%
Demand Charge D2								
Summer		799,867	0.02000	15,997	0.01346	10,770	-0.00654	-32.7%
Winter		399,933	0.04005	16,017	0.03297	13,186	-0.00708	-17.7%
Volumetric Charge	959,840		0.03994	38,336	0.03859	37,044	-0.00135	-3.4%
INDUST Net LT Cntrct	959,840		0.13603	130,569	0.08837	84,825	-0.04766	-35.0%
Industrial LT Cntrct	45,340			2,257		2,367		
TOTAL INDUSTRIAL	1,005,180		0.13214	132,826	0.08674	87,191	-0.04540	-34.4%
UTILITY ELECTRIC GEN								
Demand Charge		1,497,060	0.06752	101,081	0.03360	50,295		
Volumetric Charge								
Tier I	276,956		0.05118	14,175	0.05482	15,184		
Tier II	1,220,104		0.01447	17,655	0.01625	19,831		
TOT/AVE UEG	1,497,060		0.11300	169,161	0.02339	85,310	(83,851)M$	-49.6%
COGENERATION								
Cogen Net LT Cntrcts	400,880		0.08693	34,848	0.05699	22,844	(12,004)M$	-34.4%
Cogen LT Cntrcts	133,020			4,395		4,687		
TOT/AVE COGENERATION	533,900		0.07350	39,243	0.05157	27,531	(11,712)M$	-29.8%
NONCORE SUBTOTAL								
Net of LT Cntrcts	3,004,440		0.11824	355,258	0.06855	205,961	-0.04969	-42.0%
Include LT Cntrcts	3,182,800		0.11371	361,910	0.06693	213,015	-0.04678	-41.1%
WHOLESALE								
Demand Charges			0.05889	73,631		57,065	(16,567)M$	-22.5%
Volumetric Charge	1,250,369		0.02180	27,258	0.02339	29,245	0.00159	7.3%
TOT/AVE WHOLESALE	1,250,369		0.08069	100,889	0.06903	86,310	-0.01166	-14.5%
TOT NONCORE	4,254,809							
Net of LT Cntrcts	4,254,809		0.13825	456,148	0.06869	292,271	-0.06956	-50.3%
Include LT Cntrcts	4,433,169		0.12692	462,800	0.06752	299,325	-0.05940	-46.8%
Brokerage Fee					0.01184			

Line	Item	Units	ALLOCATION SUMMARY: SYSTEM TOTAL	CORE	NONCORE	WHOLESALE	ALLOCATION BY RATE GROUP: CORE RESIDENT.	CORE COMMERCIAL GN-10,20	NONCORE	OTHER INDUSTR.	CONTRACT INDUSTRIAL	EOR & EOR COGEN	CONTRACT COGEN	COGEN NON-EOR	UEG	WHOLESALE LONG BEACH	SDG&E CORE	SDG&E NONCORE	Note
99	PROCUREMENT COSTS																		
100	PURCHASED COST WITHOUT FAG		1487.826																
101	BROKERAGE COSTS		3.950																
102	CORE FOR PURCHASED GAS ADJUSTMENT		152.690																
103	FAG		38.451																
104	COST OF GAS	MM$	1675.126																
106	CORE & ELECT PROCUREMENT ON/THEREA		27.778 Appendix B, Table 6																
108	TRANSPORTATION COSTS																		
109	FIXED COSTS																		
110	COMMON DISTRIBUTION		343.937	307.244	36.593	0.000	237.692	69.742	3.907	25.507	1.250	0.000	1.400	0.210	0.500	0.000	0.000	0.000	ELIG.PEAK
111	DEMAND REL TRANS		96.222	53.043	29.360	13.819	38.738	14.325	1.596	10.592	0.517	0.000	1.509	0.548	10.657	1.979	5.662	4.570	COLD YEAR
112	DEMAND RELATED STORAGE		115.738	82.577	19.404	13.757	63.229	19.352	1.242	10.922	0.535	0.000	1.522	0.296	0.000	0.847	1.221	1.558	COLD YEAR
113	CUSTOMER RELATED		585.304	575.478	8.718	1.115	525.617	49.841	0.333	2.158	0.107	0.000	0.378	1.128	0.357	0.376	0.497	0.542	WEIGHTED
114	COMMODITY RELATED		0.818	0.635	0.004	0.001	0.174	0.331	0.000	0.001	0.000	0.000	0.030	0.004	0.002	0.000	0.001	0.001	AVG. YEAR
115	EOR FAG (less Brokerage)		107.925	60.673	44.894	2.358	43.741	16.931	2.107	13.257	0.447	0.000	1.878	5.721	21.264	0.512	2.016	1.329	AVG.YEAR
116	MARGINAL/BASE REVENUE		1249.876	1078.619	138.975	31.741	928.294	179.222	9.584	62.778	3.264	0.000	6.707	20.212	76.528	3.413	16.297	11.931	
117	PIPELINE DEMAND CHARGES		295.459	162.875	90.178	42.406	118.857	34.018	4.959	32.524	1.537	0.000	4.834	13.965	32.564	6.076	17.255	18.944	COLD YEAR
119	TOTAL MARGIN + PIPELINE		1514.795	1241.474	229.150	74.147	1827.252	374.202	14.584	95.252	4.651	0.000	11.241	34.178	69.878	9.488	33.762	30.877	MARGIN+PIPE
121	ECR REVENUE CONTRIBUTION		47.539	0.000	47.539	0.000						47.539							
122	ECR CONTRIBUTION ALLOCATED		-47.539	-38.256	-7.059	-2.224	-31.546	-6.650	-0.449	-2.926	-0.143	0.000	-0.249	-1.653	-2.129	-0.292	-1.041	-0.951	ECR REV. ST
123	ECR NET REVENUE EFFECT	MM$	0.000	-38.256	40.530	-2.224	-31.546	-6.650	-0.449	-2.926	-0.143	47.539	-0.249	-1.653	-2.129	-0.292	-1.041	-0.951	
125	ADJUSTED TOTAL		1514.795	1203.218	269.564	71.863	995.687	237.642	14.134	92.256	4.508	47.589	10.991	32.125	58.870	9.195	32.741	29.926	
127	COMPANY USE		17.582	7.483	8.251	2.219	5.277	2.135	0.259	1.849	0.630	2.678	0.226	0.712	2.657	0.424	0.773	1.357	AFCR RLS
128	LUAF		25.065	10.476	11.520	2.989	7.485	2.531	6.247	2.375	0.112	3.728	0.329	2.594	3.478	0.591	1.183	1.416	AFCR RLS
129	CONSERVATION-CCA		23.910	18.910	5.300	0.000	13.529	5.576	3.631	0.164	0.202	0.000	0.000	2.538	0.304	0.000	0.300	0.000	EQUAL
130	[illegible] COST GAS STORAGE		6.458	4.400	1.281	0.777	3.223	1.673	0.335	0.640	0.030	0.000	0.065	0.225	0.304	0.047	0.514	0.217	AFCR RLS
131	[illegible] EXCHANGE REVENUES		-8.732	-4.777	-2.656	-1.249	-3.521	-1.297	-0.144	-0.958	-0.047	0.000	-0.136	-0.411	-0.959	-0.179	-0.512	-0.528	COLD YEAR
132	SUB.TOTAL		64.233	36.611	23.164	4.026	23.472	10.139	1.186	7.768	0.279	0.407	0.513	1.546	5.374	0.683	1.862	2.491	
134	TRANSITION COSTS																		
135	DIRECT BILLS (reduced 20%)		69.221	33.878	25.276	10.046	24.244	9.533	1.130	7.464	0.364	0.000	1.049	3.221	12.028	1.721	3.521	4.605	AVG. YEAR
136	EXCESS COMMODITY PURCHASES		0.000	0.000	0.000	0.000	0.506	0.506	0.090	0.000	0.000	0.000	0.000	0.636	0.630	0.000	0.000	0.130	ALLOCATED
137	MINIMUM PURCHASE OBLIGATION		14.594	7.340	5.077	2.177	5.273	2.045	0.245	1.617	0.079	0.000	0.232	0.679	2.404	0.518	0.763	0.998	AVG. YEAR
138	SUB.TOTAL TRANSITION	MM$	84.194	41.219	30.753	12.222	29.623	11.578	1.375	9.081	0.443	0.000	1.304	3.919	14.634	2.337	0.214	5.602	AVG. YEAR
140	INTERUTILITY TRANS.REV.	MM$	7.798	4.403	2.038	1.146	3.213	1.190	0.132	0.879	0.043	0.000	0.125	0.378	0.881	0.149	0.470	0.512	
142	BALANCING ACCOUNTS																		
143	CORE FIXED COST ACCOUNT		5.313	5.313	0.000	0.000	3.818	1.495											CORE AVG.
144	CORE IMPLEMENTATION ACCT.		-39.771	-39.771	0.000	0.000	-28.580	-11.191											CORE AVG.
145	CORE CCA (CONSERVATION)		-67.054	-67.054	0.000	0.000	-48.761	-19.093											CORE AVG.
146	NONCORE TRANSITION		2.680	0.000	1.924	0.765			0.066	0.560	0.020	0.000	0.001	0.249	0.915	0.156	0.260	0.556	NCORE AVG.YR
147	EOR ACCOUNT		-34.496	-27.722	-5.117	-1.656	-22.938	-4.784	-0.326	-2.128	-0.104	0.000	-0.253	-0.763	-1.543	-0.212	-0.754	-0.689	EQUALIZ ELEC
148	NONCORE IMPLEMENTATION		-42.692	0.000	-42.692	0.000			-1.909	-12.607	-0.113	0.000	-1.005	-5.440	-20.316	0.000	0.000	0.000	NCORE AVG.YR
149	NONCORE CCA		-14.996	0.000	-14.996	0.000			-1.092	-12.695	-0.010	0.000	0.000	0.000	0.000	0.000	0.000	0.000	NCORE AVG.YR
150	FIXED PIPELINE DEMAND		-20.873	0.000	-19.197	-4.676			-0.771	-5.120	-0.250	0.000	-0.720	-2.199	-5.127	-0.956	-2.737	-2.993	NCORE AVG.YR
151	MIN.PURCHASE OBLIGATION		6.898	0.000	4.934	1.960			0.220	1.456	0.076	0.000	0.290	0.620	2.344	0.375	0.687	0.898	NCORE AVG.YR
152	CARRYING COST OF STORAGE		-2.260	0.000	-1.313	-0.946			-0.125	-0.740	-0.036	0.000	-0.143	-0.311	0.000	-0.057	-0.625	-0.263	NCORE PEAK
153	TAKE-OR-PAY (reduced by 20%)		27.143	0.000	19.852	7.090			0.807	5.062	0.206	0.000	0.659	2.330	9.147	1.509	2.765	3.417	NCORE AVG.YR
154	COGENERATION SHORTFALL		0.000	0.000	0.000	0.000			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	UEG/COGEN F.
155	NFCA BASE REVENUE CHANGE		-1.846	0.000	-1.321	-0.525			-0.059	-0.390	-0.019	0.000	-0.056	-0.168	-0.629	-0.100	-0.184	-0.241	NCORE NCRT.
156	NRSA-NEGOTIATED REVENUE STABILITY		-1.891	0.000	-1.353	-0.538			-0.060	-0.400	-0.019	0.000	-0.057	-0.172	-0.644	-0.103	-0.188	-0.246	NCORE NCRT.
157	SUB.TOTAL BALANCING	MM$	-184.843	-130.034	-54.284	0.375	-76.461	-30.573	-3.947	-25.993	-1.249	0.000	-1.075	-5.650	-15.536	0.601	-0.760	0.442	SUMMATION
159	LONG-TRM CONTR.SHORTFALL		-8.110	0.000	-8.110	0.000	0.000	0.000	0.000	0.000	-1.741	0.000	-0.378	0.000	0.000	0.000	0.000	0.064	CONTRACT SC
160	L-TRM SHORTFALL SPREAD		8.110	4.058	2.856	1.203	2.916	1.142	0.135	0.894	0.000	0.000	0.000	0.386	1.441	0.250	0.422	0.552	OUT/CHECP.
161	LONG-TRM SHORTFALL NET	MM$	0.000	4.058	-5.262	1.203	2.916	1.142	0.135	0.894	-1.741	0.000	-0.378	0.386	1.441	0.250	0.422	0.552	

LONG-TERM CONTR.SHORTFALL		-0.010	0.000	-0.010	0.000	[illegible]	[illegible]	0.030	0.000	-2.741	0.600	-0.270	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	CONTRACT [illegible]
SHORTFALL SPREAD		0.118	0.050	2.556	1.203	2.916	1.142	0.125	0.894	0.600	0.004	0.030	0.286	1.441	0.220	0.022	0.552	CNT/THERM
LONG-TERM SHORTFALL NET	M$	0.304	4.650	-5.262	1.203	2.916	1.142	0.125	0.894	-1.741	0.600	-0.570	0.286	1.441	0.220	0.022	0.552	
Long-Term Contract w/SB	$.[illegible]	0.040	3.124	2.226	0.624	2.252	0.882	0.135	0.699	0.000	0.800	0.300	0.299	2.192	0.170	-5.943	0.426	AVG. YEAR [illegible]
Conform.sin SB Core alloc 78.441																		
STORAGE BANKING	M$	-1.243	0.300	-0.605	-0.035			-0.657	-0.343	-0.017	0.000	-0.047	-0.143	0.000	-0.026	-0.287	-0.121	N-CORE PEAK
ADJ.FOR UNCOLLECT (NONE TO WHLSLE)		0.500	0.255	0.046	-0.311	0.220	0.044	0.003	0.020	0.000	0.000	0.000	0.007	0.015	-0.046	-0.131	-0.133	WHOLESALE CO
																		SOCAL'S ONC
TRANSPORTATION REVENUE	M$	1516.527	1162.905	260.161	85.461	963.140	179.064	13.046	65.350	2.347	53.996	4.630	33.865	74.699	13.515	32.648	29.297	
TRANSPORT RATE	CNT/THERM	14.993	27.439	5.725	7.322	31.727	16.750	9.255	9.143	5.213	3.570	3.516	0.437	4.920	5.610	0.932	0.827	
											AVERAGE UEG/COG =		5.663					
REVENUE CHECK NUMBER= 1516.527																		
SYSTEM TOTAL COSTS	REV. M$	3191.763	2329.919	733.371	85.461	1865.131	524.8.8	41.000	222.979	2.347	74.086	4.630	53.713	330.026	13.515	32.648	39.297	
TOTAL RATE	CNT/THERM	14.993	55.270	5.725	7.322	59.536	44.479	9.255	9.148	5.213	3.570	3.516	0.437	4.920	5.610	0.902	0.827	AVG.CORE RAT
					AVERAGE CORE AVG.=		55.278				AVERAGE UEG/COG =		5.663					AVG.COGEN/UE
	RATE DISCOUNTING ADJUSTMENTS							13.392	85.363	2.347	= ALLOCATED REVENUE: ALL TRANSPORT COSTS INCLUDING SHRINKAGE.							
FIXED COST REV.AT DISCOUNTED RATE											=MAXIMUM WITH RATE DISCOUNTING:ADJUST FACTOR BELOW UNTIL "ALLOCATED=MAX.REV."							
RATE DISCOUNT ADJUSTMENT FACTOR						1.0000	1.0000	0.95853	0.96786	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	

(END OF APPENDIX C)

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1989 to September 30, 1990

TABLE 1

ADOPTED GAS DELIVERIES

THROUGHPUT TYPE	GAS DELIVERIES (Mdth)
Residential	32,484.0
Commercial Core	10,707.3
Commercial Non-Core	8,744.2
Retail UEG	30,528.6
Cogeneration	17,535.5
Company use	130.0
Unaccounted for	1,001.3
TOTAL GAS DELIVERIES	101,130.9 Mdth

TABLE 2

ADOPTED GAS DELIVERIES by CUSTOMER CLASS

CUSTOMER CLASS		PRIORITY	GAS DELIVERIES (Mdth)
Residential deliveries			32,292.0
Residential deliveries			192.0
Commercial	GN-1C	P-1	9,911.8
Commercial	GN-2C	P-2A	674.0
Commercial	GN-2ST	P-1	121.5
Comm/Ind	GTCGC	P-3A	100.0
Comm/Ind	GTCGNC	P-3A	15,791.4
Comm/Ind	GTCGST	P-3A	1,644.1
Comm/Ind	GTNCC	P-3B	298.1
Comm/Ind	GTNCNC	P-3B	8,276.2
Comm/Ind	GTNCST	P-3B	169.9
Total Comm/Ind deliveries			36,987.0
UEG sales	GPNC	P-2A	163.0
UEG sales	GPNC	P-5	23,416.6
UEG sales	GPNC	P-3B	6,949.0
Total UEG deliveries			30,528.6
Company use		P-1	130.0
Unaccounted for		P-1	1,001.3
TOTAL GAS DELIVERIES			101,130.9 Mdth

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1989 to September 30, 1990

TABLE 3

ADOPTED DELIVERIES by PRIORITY RANKING

PRIORITY	GAS DELIVERIES (Mdth)
P-1	43,648.6
P-2A	837.0
P-2B	0.0
P-3A	17,535.5
P-3B	15,693.2
P-5	23,416.6
TOTAL GAS DELIVERIES	101,130.9 Mdth

TABLE 4

ADOPTED DELIVERIES by PORTFOLIO CLASS

		GAS DELIVERIES (Mdth)
CORE & CORE-ELECT PORTFOLIO DELIVERIES		
Residential deliveries		32,292.0
Commercial	GN-1C	9,911.8
Commercial	GN-2C	674.0
Comm/Ind	GTNCC	298.1
Comm/Ind	GTCGC	100.0
Subtotal		43,275.9
Company use		57.5
Unaccounted for		442.7
TOTAL		43,776.1 Mdth
NON-CORE PORTFOLIO DELIVERIES		
Comm/Ind	GTCGNC	15,791.4
Comm/Ind	GTNCNC	8,276.2
UEG sales	GPNC	163.0
UEG sales	GPNC	23,416.6
UEG sales	GPNC	6,949.0
Subtotal		54,596.3
Company use		72.5
Unaccounted for		558.6
TOTAL		55,227.3 Mdth

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1989 to September 30, 1990

TABLE 4 (cont'd)

ADOPTED DELIVERIES by PORTFOLIO CLASS

	GAS DELIVERIES (Mdth)
SHORT-TERM TRANSPORT	
Residential deliveries	192.0
Commercial GN-2ST	121.5
Comm/Ind GTCGST	1,644.1
Comm/Ind GTNCST	169.9
TOTAL	2,127.5 Mdth
TOTAL GAS DELIVERIES	101,130.9 Mdth

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1989 to September 30, 1990

TABLE 5

ADOPTED COSTS

	VOLUMES (Mdth)	PRICE ($/dth)		COSTS (000's of $)
Core & Core-Elect Supplies				
Core/Core-elect purchase	43,776			96,368.7
Core & Core-elect WACOG		2.2014		
Non-Core Supplies				
Non-core purchases & WACOG	55,227	2.2014		121,577.5
SDG&E's Balancing/Tracking accounts (adjusted)				
Core Purchased Gas Account (CPGA)				2,492.0
Other Core accounts:				
Core Fixed Cost Account (CFCA)			(1,874.6)	
Core Implementation Account (CIA)			(4,090.3)	(5,964.9)
Non-Core accounts:				
Negotiated Revenue Stability Account (NRSA)			(1,276.3)	
Enhanced Oil Recovery Account (EORA)			0.0	
Noncore Implementation Account (NIA)			(6,348.9)	
Minimum Purchase Obligation (MPO)			0.0	
Pipeline Demand Charges (PDC)			0.0	
Noncore Transition Cost Account (NTCA)			1,277.8	
Cogeneration Shortfall Account (CSA)			0.0	
Carrying Cost of Storage			0.0	
Take-or-Pay			0.0	
Fixed Cost Acct. (NFCA) Marg. Shortfall			0.0	(6,347.3)
SoCal's Balancing/Tracking accounts allocated to SDG&E				
Non-Core accounts:				
Negotiated Revenue Stability Account (NRSA)			(435.0)	
Enhanced Oil Recovery Account (EORA)			(1,444.0)	
Noncore Implementation Account (NIA)			0.0	
Minimum Purchase Obligation (MPO)			1,585.0	
Pipeline Demand Charges (PDC)			(5,720.0)	
Noncore Transition Cost Account (NTCA)			618.0	
Cogeneration Shortfall Account (CSA)			0.0	
Carrying Cost of Storage			(888.0)	
Take-or-Pay			6,382.0	
Fixed Cost Acct. (NFCA) Marg. Shortfall			(425.0)	(327.0)

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1989 to September 30, 1990

TABLE 5 (cont'd)

ADOPTED COSTS

	VOLUMES (Mdth)	PRICE ($/dth)	COSTS (000's of $)	
Company use and Unaccounted for				
Core Company Use	57	2.2014	126.5	
Core Unaccounted For	443	2.2014	974.6	
Total	500			1,101.2
Non-core Company Use	73	2.2014	159.6	
Non-core Unaccounted For	559	2.2014	1,229.6	
Total	631			1,389.2

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1989 to September 30, 1990

TABLE 6

ADOPTED PORTFOLIO PRICES

	VOLUMES (Mdth)	COSTS (000's of $)
Core & Core-elect Portfolio		
Core & Core-elect purchases	43,776	96,368.7
Less: Company use & unaccounted for	500	1,101.2
Add: Core Purchased Gas Account (CPGA)		2,492.0
Subtotal		97,759.5
Add: FF&U at 2.490%		2,434.2
CORE & CORE-ELECT SALES	43,276	100,193.8
CORE & CORE-ELECT PORTFOLIO PRICE		$2.3152 /dth
Non-Core Portfolio		
Non-core porfolio demand	55,227	121,577.5
Less: Company use & unaccounted for	631	1,389.2
Subtotal		120,188.2
Add: FF&U at 2.490%		2,992.7
Subtotal		123,180.9
NON-CORE PORTFOLIO SALES	54,596	123,180.9
NON-CORE PORTFOLIO PRICE ($/dth)		$2.2562 /dth

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1989 to September 30, 1990

TABLE 7

ADOPTED REVENUE REQUIREMENTS

		AMOUNTS (000's of $)
PROCUREMENT REVENUE REQUIREMENT		
Total Core Procurement Revenue	100,193.8	
Total Non-core Procurement Revenue	123,180.9	
TOTAL PROCUREMENT REVENUE REQUIREMENT		223,374.7
TRANSMISSION REVENUE REQUIREMENT		
SDG&E's authorized gas margin:		
Common distribution	43,119.5	
Demand related transmission	8,855.6	
Demand related storage	569.5	
Customer related	66,190.7	
Commodity related	1,544.7	
50% Administrative & General	9,859.0	130,139.0
Carrying cost of storage		1,009.0
Other Core Balancing/tracking accounts	(5,964.9)	
Non-Core Balancing/tracking accounts	(6,347.3)	
Add: FF&U at 2.4900%	(306.6)	(12,618.8)
Core Company use and unaccounted for gas	1,101.2	
Non-Core Company use and unaccounted for gas	1,389.2	
Add: FF&U at 2.4900%	62.0	2,552.4
Net LIRA revenues		168.0
Miscellaneous revenue adjustment		(3,152.0)
SDG&E's F&U on SoCal costs allocated to SDG&E's retail		1,223.0
SoCal's authorized gas margin allocated to SDG&E:		
Common distribution	0.0	
Demand related transmission	11,832.0	
Demand related storage	13,110.0	
Customer related	1,039.0	
Commodity related	1.0	
50% Administrative & General	2,346.0	28,328.0

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1989 to September 30, 1990

TABLE 7 (cont'd)

ADOPTED REVENUE REQUIREMENTS

	AMOUNTS (000's of $)
Other SoCal costs allocated to SDG&E:	
Pipeline demand charges	36,331.0
Carrying cost of storage	730.0
Company use	1,795.0
Unaccounted for	2,498.0
Net long-term shortfall	973.0
Net long-term Contract w/SoCal	(5,517.0)
Storage Banking	(409.0)
Adjustment for uncollectibles	(265.0)
Transition costs	9,886.0
Net EOR adjustment	(1,992.0)
Non-Core Balancing/tracking accounts	(327.0)
Interutility transportation revenues	982.0
Exchange revenues	(1,070.0)
TOTAL TRANSMISSION REVENUE REQUIREMENT	191,263.7
NET REVENUE REQUIREMENT	$414,638.4

(end of appendix d)

SAN DIEGO GAS AND ELECTRIC COMPANY
ALJ PROPOSED REVENUES AND ILLUSTRATIVE RATES
CORE

CUSTOMER CLASS	THROUGH-PUT (MTh)	PRESENT RATE ($/Th)	PRESENT REVENUES (M$)	PROP RATE GAS ($/Th)	PROP RATE NON-GAS ($/Th)	PROP RATE TOTAL ($/Th)	PROP REVS GAS (M$)	PROP REVS NON-GAS (M$)	PROP REVS TOTAL (M$)	REVENUE %
	(B)	(C)	(D)	(G)	(I)		(H)	(K)		
RESIDENTIAL GR										
Tier I	172,918	0.46716	80,780	0.23152	0.23564	0.46716	$40,034	$40,746	$80,780	0.00%
Tier II	67,734	0.83699	56,693	0.23152	0.57911	0.81063	$15,682	$39,225	$54,907	-3.15%
Employee Discount			($297)						($297)	
Residential Ave/Tot	240,652		137,177				$55,716	$79,972	$135,391	-1.30%
RESIDENTIAL GS, GT										
Tier I	8,546	0.46716	3,992	0.23152	0.23564	0.45716	$1,979	$2,014	$3,992	0.00%
Tier II	2,058	0.83699	1,722	0.23152	0.57911	0.81063	$476	$1,192	$1,668	-3.15%
Unit Discount			(2,133)						($2,133)	
Residential Ave/Tot	10,604		3,582				$2,455	$3,205	$3,528	-1.51%
RESIDENTIAL GM										
Tier I	46,261	0.46716	21,611	0.23152	0.23564	0.46716	$10,710	$10,901	$21,611	0.00%
Tier II	10,522	0.83699	8,807	0.23152	0.57911	0.81063	$2,436	$6,093	$8,529	-3.15%
Residential Ave/Tot	56,783		30,418					$16,994	$30,141	-0.91%
LOW INCOME SALES										
Tier I	12,134	0.46716	5,668	0.23152	0.16557	0.39709	$2,809	$2,009	$4,818	-15.00%
Tier II	4,667	0.83699	3,906	0.23152	0.42721	0.65873	$1,080	$1,994	$3,074	-21.30%
[illegible]sidential ave/Tot	16,801		9,575				$3,890	$4,003	$7,892	-17.57%
LESS TRANSP. vol adj	(1,920)	0.23152	(445)	0.23152		0.23152	($445)		($445)	0.00%
RESIDENTIAL -GL	4	9.87	39		$13.10	$13.10			$54	36.78%
RESIDENTIAL TOTAL										
CORE COMMERCIAL										
GN-1 Service Charge	326,088	$5.00	1,630		$5	$5.00		$1,630	$1,630	0.00%
GN-2 Service Charge	240	$60.00	14		$60	$60.00		$14	$14	0.00%
Winter										
Tier 1	33,612	0.70313	23,634	0.23152	0.42584	0.65736	$7,782	$14,313	$22,095	-6.51%
Tier 2	14,547	0.41580	6,049	0.23152	0.15632	0.38784	$3,368	$2,274	$5,642	-6.72%
Summer										
Tier 1	46,431	0.53842	24,999	0.23152	0.32417	0.55569	$10,750	$15,051	$25,801	3.21%
Tier 2	14,113	0.37676	5,317	0.23152	0.14635	0.37787	$3,267	$2,065	$5,333	0.29%
Commodity Ave/Total	108,703		59,999				$25,167	$33,704	$58,871	-1.88%
Transport Vol. Adjustment	(1,215)	0.23152	(281)	0.23152		0.23152	($281)		($281)	0.00%
Commercial Total	108,703		61,644				$24,886	$35,349	$60,235	-2.29%
TOTAL CORE	433,543		198,820				$86,502	$124,174	$205,010	
[illegible]S IGNITOR ADJUSTMENT	(1,630)			0.23152	0.32519	0.55671	($377)	($530)	($907)	
TOTAL NET CORE									$204,103	

SAN DIEGO GAS AND ELECTRIC
ALJ PROPOSED REVENUES AND ILLUSTRATIVE RATES
NONCORE

NONCORE CUSTOMER CLASS	ADJUSTED FORECAST DELIVERIES (MTH)	HISTORICAL BILLING DETERMINANTS (MTH/CUST)	PRESENT RATES EFFECTIVE 7/1/88 $/TH OR $/MO	PRESENT REVENUES EFFECTIVE 7/1/88 (M$)	PROPOSED RATE $/TH OR $/MO	PROPOSED REVENUES TOTAL NON-GAS (M$)	PROPOSED CHANGE ($/TH)	PROPOSED CHANGE (%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
COMMERCIAL/INDUST								
Customer Charge				158		218	0.00069	38.3%
Demand Charge D1		87,442	0.06799	5,945	0.05212	4,558	-0.01587	-23.3%
Demand Charge D2								
Summer		83,254	0.04114	3,425	0.02632	2,192	-0.01482	-36.0%
Winter		42,151	0.07231	3,048	0.02996	1,263	-0.04235	-58.6%
Volumetric Charge	87,442		0.07197	6,293	0.04953	4,331	-0.02244	-31.2%
TOTAL/AVE COMM/IND	87,442		0.21579	18,869	0.14365	12,561	-0.07214	-33.4%
UTILITY ELECTRIC GEN:								
Demand Charge		12	$3,326	39,912	$1,572	18,865		
Volumetric Charge:								
Tier I *	57,806		0.06097	3,524	0.05163	2,984		
Tier II	247,480		0.02980	7,375	0.01957	4,844		
TOT/AVE UEG	305,286		0.11214	34,235	0.08744	26,693	(7,542)M$	-22.0%
COGENERATION								
Cogen Net of GC-2	175,355		0.11214	19,664	0.08744	15,332	(4,332)M$	-22.0%
TOT/AVE COGENERATION	175,355		0.11214	19,664	0.08744	15,332	(4,332)M$	-22.0%
TOTAL NONCORE	568,083		0.13825	72,768	0.09609	54,587	-0.04216	-30.5%

5 :SAN DIEGO GAS & ELECTRIC
6 :DATE: 20-Nov-89
7 :CASE : SPRING 1989 ACAP
8 :CACD
9 :ALJ PROPOSED
10
11
12 : SAN DIEGO GAS & ELECTRIC 1989 ACAP

Row		SDG&E ALLOCATIONS TO SOCAL	SDG&E'S OWN COSTS	SYSTEM SDG&E + SOCAL COSTS	CORE	NON-CORE	RESIDENTIAL	GN-1	GN-2A & UEG IGNITER	INDUSTRIAL	COGEN	UEG GAS DEPT. (GN-3 TO EX-5)	ALLOCATION BASIS
14	22.814 ¢CORE COST OF GAS, CNT/THERM				ALLOCATION SUMMARY			ALLOCATION GROUP					ALLOCATION BASIS
15	22.014 ¢NONCORE COST OF GAS, CNT/THERM						CORE			NONCORE			
16	0.00124 ¢SDG&E CO.USE WITHOUT F&U												
17	0.01611 ¢SDG&E LUAF WITHOUT F&U												
18	0.02284 ¢FRANCHISE & UNCOLLECT. RETAIL												
19	0.01730 ¢FRA & UNCOL SYSTEM (ex UEG)												
21	PROCUREMENT COSTS												
22	GAS COSTS WITHOUT SDG&E F&U	0.000	215.456	215.456									
23	PGA PURCHASED GAS ADJUSTMENT	N/A	2.492	2.492									
24	SDG&E F&U FOR GAS PURCHASED	0.000	5.627	5.627									
25													
26	GAS COSTS WITH SDG&E F&U MM$	0.000	223.575	223.575									
27													
28	PROCUREMENT RATES CENTS/THERM				23.152 :Appendix D, Table 6, Page 10								RATES:CORE/NCORE/TRANS. WEIGHTED AVG
29													
30	TRANSPORTATION COSTS												
31	FIXED COSTS												
32	COMMON DISTRIBUTION	0.000	43.120	43.120	34.127	8.993	27.281	6.311	0.533	3.942	5.054	0.009	N.C. PEAK MONTH
33	DEMAND RELATED TRANSMISSION	11.832	8.854	20.686	10.394	10.292	7.962	2.219	0.212	1.897	3.692	4.769	COLD YEAR THRU-PUT
34	DEMAND RELATED STORAGE	13.110	0.570	13.680	10.184	3.496	8.063	1.945	0.176	1.294	2.201	0.050	COLD YEAR PEAK SEASON THRU-PUT
35	PIPELINE DEMAND CHARGES	34.331	0.000	34.331	18.247	16.084	13.979	3.896	0.372	3.331	6.483	6.270	COLD YEAR THRU-PUT
36	CUSTOMER RELATED- DISTRIBUT.	0.000	66.191	66.191	65.229	0.962	61.965	3.293	0.031	0.152	0.529	0.281	NUMBER CUSTOM. WGHTED BY INVESTMENT
37	CUST REL TRANSM. INTERCONNECT	1.039	0.000	1.039	0.522	0.517	0.400	0.111	0.011	0.095	0.185	0.237	COLD YEAR THRU-PUT
38	COMMODITY RELATED	0.001	1.545	1.546	0.670	0.876	0.502	0.153	0.015	0.135	0.271	0.469	AVG YEAR THRU-PUT
39	S&I & A&G	2.346	9.859	12.205	5.291	6.914	3.965	1.210	0.117	1.067	2.144	3.704	AVG YEAR THRU-PUT
40	ECR ADJUST.	-1.992	N/A	-1.992	-1.003	-0.912	-0.654	-0.325	-0.021	-0.183	-0.341	-0.379	FUNCTIONALIZED SOCAL COSTS
41	CONTRACT ADJUSTMENT (see B4, B5)	0.000	N/A	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	FUNCTIONALIZED SOCAL COSTS, EXCL UEG
42	SDG&E CO.USE	N/A	0.296	0.296	0.124	0.162	0.093	0.028	0.003	0.025	0.050	0.087	INCLUDES
43	SDG&E LUAF	N/A	2.204	2.204	0.956	1.249	0.726	0.210	0.021	0.193	0.387	0.669	AVG. YEAR THRU-PUT
44													
45	SUBTOTAL FIXED MM$	62.667	132.629	195.296	144.659	50.637	124.920	19.160	1.471	11.947	20.640	18.050	SUMMATION ADJUSTED FIXED COSTS
46													
47	BALANCING/MISCELLANEOUS:												
48													
49	SDG&E BALANC./TRACKING												
50	CSA COGEN SHORTFALL TRACK. ACCT.	0.0	0.000	0.000	0.000	0.000					0.000	0.000	COGEN & UEG THRU-PUT, CNT/THERM
51	CFCA CORE FIXED COST BAL. ACCT.	0.0	-1.921	-1.921	-1.921	0.000	-1.429	-0.429	-0.042				CORE THRU-PUT, CNT/THERM
52	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

52	:NTCA NONCORE TRANSITION BAL.ACCT.		N/A	[illegible]	[illegible]	0.000	[illegible]	0.000	0.000	0.000	[illegible]	[illegible]	[illegible]	:NONCORE THRU-PUT,EQUAL CNT/THERM
53	:NCGA CORE IMPLEMENT.BAL.ACCT.		N/A	-4.192	-4.192	-4.192	0.000	-3.[illegible]	-0.[illegible]	-0.[illegible]				:CORE THRU-PUT,CNT/THERM
54	:NCGA NONCORE IMPLEMENT.BAL.ACCT.		N/A	-5.537	-5.537	0.000	-5.537	0.000	0.000	0.000	-1.054	-2.014	-[illegible]	:NONCORE THRU-PUT,EQUAL CNT/THERM
55	:NGSA NEGOTIATED STABILITY BAL.ACC.		N/A	-1.[illegible]	-1.[illegible]	0.000	-1.[illegible]				-0.[illegible]	-0.[illegible]	-0.[illegible]	:NONCORE THRU-PUT,EQUAL CNT/THERM
56	: SUBTOTAL ECONE ACCTS.		0.000	-12.[illegible]	-12.[illegible]	-[illegible]	-[illegible]	-4.[illegible]	-1.[illegible]	-0.[illegible]	-1.[illegible]	-2.[illegible]	-2.[illegible]	:SUMMATION
57														
58	: SOCAL BALANCE/TRACKING ACCT.													
59	:NTCA AND NGSA		0.183	N/A	0.183	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	:AVG YEAR THRU-PUT
60	:PIPELINE DEMAND TRACKING ACCT.		-5.[illegible]	N/A	-5.[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	:COLD YEAR THRU-PUT
61	:MIN.PURCHASE OBLIGATION TRACK.AL		0.[illegible]	N/A	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	:AVG YEAR THRU-PUT
62	:CARRY.COST GAS STORAGE TRACK.A		-0.[illegible]	N/A	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	0.[illegible]	:COLD YEAR PEAK SEASON THRU-PUT
63	:NPCA (NPSIO) ADJUSTMENT		-0.[illegible]	N/A	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	:AVG YEAR THRU-PUT
64	:TAKE-OR-PAY OBLIGATION		[illegible]	N/A	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	:AVG YEAR THRU-PUT
65	:EOR TRACKING		-[illegible]	N/A	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	:EX allocation of SOCAL fixed costs
66	: SUBTOTAL SOCAL BALANCES		-0.[illegible]	0.000	-0.[illegible]	-0.[illegible]	[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	-0.[illegible]	0.[illegible]	:SUMMATION
67														
68	: SOCAL MISC.FORECAST EXPENSES													
69	:LEAPS		[illegible]	N/A	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	:AVG YEAR THRU-PUT
70	:COMPANY USE		[illegible]	N/A	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	:AVG YEAR THRU-PUT
71	:CARRY.COST GAS STORAGE		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	:COLD YEAR PEAK SEASON THRU-PUT
72	:EXCHANGE REVENUE		-[illegible]	N/A	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	[illegible]	:COLD YEAR THRU-PUT
73	:INTERUTILITY REVENUE		[illegible]	N/A	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	:COLD YEAR THRU-PUT
74	:LONG-TERM CONTRACT SHORTFALL*		0.[illegible]	N/A	[illegible]	[illegible]	0.[illegible]	[illegible]	0.[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	:AVG YEAR THRU-PUT
75	:STORAGE BANKING FEE.		-[illegible]	N/A	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	[illegible]	:COLD YEAR PEAK SEASON THRU-PUT
76	:MISCELLANEOUS [illegible]		-[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	:FUNCTIONALIZED SOCAL COSTS,EQUAL [illegible]
77	: SUBTOT.SOCAL MISC.FORECAST		[illegible]	[illegible]	7.[illegible]	3.[illegible]	[illegible]	2.[illegible]	0.[illegible]	0.[illegible]	[illegible]	1.[illegible]	1.[illegible]	
78														
79	: BALANCING/TRACK/MISC.	MM$	[illegible]	-10.[illegible]	-3.[illegible]	-3.[illegible]	-1.[illegible]	-2.[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	-[illegible]	:SUMMATION
80														
81	DIRECT BILLS		0.125	N/A	0.125	2.[illegible]	[illegible]	2.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	1.[illegible]	2.447	:AVG YEAR THRU-PUT
82	:EXCESS COMMODITY PURCHASES		0.000	N/A	0.000	0.000	0.000	0.000	0.000	0.000	0.[illegible]	0.000	0.[illegible]	:AVG YEAR THRU-PUT
83	:MINIMUM PURCHASE OBLIGATIONS		0.761	N/A	0.761	0.763	0.[illegible]	0.572	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	0.[illegible]	:AVG YEAR THRU-PUT
84	:SOCAL-SDG&E CONTRACT SHORTFALL		0.426	N/A	0.426	0.000	0.[illegible]	0.000	0.000	0.000	0.[illegible]	0.132	0.[illegible]	
85	:SOCAL-SDG&E CORE CONTRACT		-5.943	N/A	-5.943	-5.943	0.000	-4.453	-1.[illegible]	-0.[illegible]				:CORE ONLY
86	: SUBTOT.TRANSMISSION COSTS	MM$	0.561	0.000	0.569	-1.657	[illegible]	-1.242	-0.379	-0.[illegible]	[illegible]	1.843	[illegible]	:SUMMATION
87	:BSCT [illegible] REV. [illegible]		N/A	0.000	0.000	0.000	0.000	[illegible]	0.[illegible]	0.[illegible]				
88	:LOW INCOME ASSISTANCE (LIRA)		N/A	-1.374	-1.374	-1.374	0.000	-1.374						:QUALIFIED LOW INCOME RESIDENTIAL
89	:LIRA A&G & DISCOUNT EXPENSES		N/A	1.563	1.563	1.291	0.272	0.958	0.330	0.025	0.272	0.000	0.000	:*
90														
91	:TRANSPORTATION REVENUE TOTALS	MM$	71.943	122.413	194.224	139.419	54.934	121.461	18.895	1.442	12.763	21.779	20.374	:SUMMATION
92														
93	TRANSPORTATION RATES	CENTS/THERM			19.933	32.159	9.698	37.291	19.063	13.042	14.576	12.420	6.716	:UEG/COGEN,CNT/THERM*
94											AVERAGE UEG/CORE=		0.804	
95	:ALL COSTS 410.438	MM$	71.943	345.784	417.729	241.433	177.004	196.222	41.842	2.370	32.126	57.628	87.241	:SUMMATION
96														
97	:MISCELLANEOUS REV.ADJUSTMENT**	MM$			-3.152	-2.300	-0.891	-1.970	-0.306	-0.023	-0.207	-0.353	-0.331	:EQUAL PERCENT NONGAS COSTS
98	:ADJUSTED TOTAL COSTS	MM$			414.577	239.134	176.113	194.252	41.523	2.347	31.919	57.284	86.914	:SUMMATION

99													
100	TOTAL RATES	CENTS/THERM	17.433	55.510	9.698	60.513	42.215	38.196	14.576	12.420	6.716	:RATE DESIGN AVERAGES ALL CORE RATES.
101			AVERAGE CORE=	0.4656336		AVERAGE CORE=	0.5211328		AVERAGE UEG/CORE=		0.804	:RATE DESIGN AVERAGES UEG& COGEN RATES
102	:CORE & CORE ELECT SALES	:MM THERMS	432.729	428.778	3.951	322.720	99.118	0.740	2.951	1.000	0.000	
103	:NONCORE SALES	:MM THERMS	545.962	1.630	544.332	0.000	0.000	1.630	82.712	157.914	303.656	
104	:TRANSPORTATION	:MM THERMS	21.279	3.135	18.144	1.920	0.000	1.215	1.699	16.441	0.000	
105	:THRU-PUT DELIVERIES	:MM THERMS	999.996	433.543	566.453	324.840	99.118	9.585	87.642	175.355	303.656	:CURTAIL UEG 51.3 MMTHERMS IN COLD YR
106	:COMPANY USE & LUAF	:MM THERMS	13.647									
107	:THRU-PUT REQUIREMENTS	:MM THERMS	1011.643									

(END OF APPENDIX E)