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Decision 91-12-075 December 20, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of SOUTHERN CALIFORNIA GAS COMPANY for authority to revise its rates effective October 1, 1991, in its Biennial Cost Allocation Proceeding. (U 904-G)	Application 91-03-039 (Filed March 15, 1991)
In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902-G) for authority to revise its rates effective October 1, 1991, in its Biennial Cost Allocation Proceeding.	Application 91-03-066 (Filed March 29, 1991)

(Appearances are listed in Appendix A.)

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OPINION

Summary

This decision reduces the gross revenue of Southern California Gas Company (SoCal) by $106.9 million (Appendix B) and increases the gross revenue of San Diego Gas & Electric Company (SDG&E) by $15.6 million (Appendix C). Included in SoCal's new revenue requirement are (1) $45 million in attrition revenue increases authorized in Resolution G-2974 and (2) credits (with interest) to core ratepayers of $1.47 million and $2.229 million in accordance with Ordering Paragraphs 2 and 3, respectively, of Decision (D.) 91-09-026.

SoCal's core rates are reduced $200.5 million or 8.04% including a $149.1 million (8.22%) reduction of residential rates. The median residential bill is:

	Present Rates	Adopted Rates	Change
Summer @ 25 th/Month	$17.18	$16.06	-6.5%
Winter @ 55 th/Month	$31.45	$29.94	-4.8%

SoCal's noncore rates are increased by $98.0 million or 39.18% (Appendix B). The two primary reasons for the noncore increases are an increase in interstate pipeline demand charges and the elimination of the overcollection in noncore balancing accounts. In last year's Annual Cost Allocation Proceeding (ACAP) (D.90-11-023) rates for the noncore were reduced by $88 million to amortize the overcollection in the noncore balancing accounts.

SDG&E's core rates will increase by $12.3 million (4.9%) (Appendix C) and its noncore rates by $3.3 million (1.7%) (Appendix C). A typical residential bill is:

	Present Rates	Adopted Rates	Change
Summer @ 20 th/Month	$10.66	$11.28	5.8%
Winter @ 47 th/Month	$24.40	$25.92	6.2%

The most contentious issue in this proceeding was cost allocation. SoCal and most interested parties asserted that more costs were allocated to noncore customers than was reasonable. The decision finds that there is insufficient evidence to shift Administrative and General (A&G) costs more toward the core. The request to exempt certain of SoCal's noncore customers (those who transport their own gas on the interstate system) from paying a portion of SoCal's interstate demand charges is denied.

This decision denies the request of the City of Vernon for wholesale rates and denies the request of the City of Long Beach for a low rate so that it might compete with SoCal to provide service to Southern California Edison Company (Edison). The decision authorizes SoCal to recover its previously authorized brokerage fees but denies SoCal's request to recover losses between August 1, 1991 and the effective date of this decision.

This decision was issued as a Proposed Decision to which the parties submitted comments. Those comments have been considered and changes have been made in response to those comments and a review of the record.

I. Background

SoCal seeks in its Biennial Cost Allocation Proceeding (BCAP) to revise its rates effective October 1, 1991, or as soon thereafter as possible.

The purpose of this application is (1) to allocate among customers the nongas costs of service previously authorized by the Commission for recovery in rates, (2) to reflect in rates the amortization of the balances forecast as of September 30, 1991 in various balancing and tracking accounts previously authorized by the Commission, and (3) to reflect in rates the forecast cost of gas for core customers and other related costs paid to suppliers and transporters of gas purchased by SoCal. Pursuant to

D.90-09-089, this application employs a 24-month forecast period, running from October 1, 1991 to September 30, 1993. For convenience, SoCal presented forecast data in this application separately for the first and second 12-month periods in the 24-month forecast period.

SoCal presented compliance rates that are produced by application of the Commission's previously adopted cost allocation and rate design guidelines to forecasts of demand and throughput. SoCal also presented alternative rates produced by certain modifications proposed by it to those previously adopted cost allocation and rate design guidelines. The rate changes proposed by SoCal reflect and pass through changed costs for services and commodities furnished by it, and will not cause SoCal to deviate from the rate of return last authorized by the Commission.

SoCal proposes rates that would decrease total revenue collected by approximately $142 million annually as compared to revenue at present rates. Assuming no change in cost allocation guidelines, revenue from core customers will decrease by approximately $278 million annually, approximately an 11% decrease over core revenue at present rates. Assuming no change in cost allocation guidelines, revenue from noncore customers, exclusive of revenue to recover gas costs, will increase by approximately $136 million annually, approximately a 39% increase from noncore nongas revenue at present rates. This decision authorizes an overall decrease in SoCal's rate of $152.3 million, including a core decrease of $230.4 million and a noncore increase of $82.8 million.

SDG&E in its biennial cost allocation program seeks relief similar to SoCal's to reflect and allocate in rates SDG&E's balancing account balances forecast as of September 30, 1991, and SDG&E's nongas costs and gas commodity costs which it expects to incur in the forecast period to provide gas service.

SDG&E proposes to increase total gas rates by $20.6 million on an annual basis, which constitutes a total system average rate increase of 4.5%. This decision authorizes an $11.1 million increase.

The requested effective date for the rates is October 1, 1991, or as soon thereafter as possible.

A number of parties intervened and presented proposals which supported SoCal's request for a reallocation of costs from noncore to core, and in some instances, went far beyond SoCal's request. This reallocation of costs would increase core rates by approximately $160 million. Issues other than cost allocation were raised by some parties. The parties filing briefs are SoCal, SDG&E, Division of Ratepayer Advocates (DRA), Toward Utility Rate Normalization (TURN), Pacific Gas and Electric Company (PG&E), Edison, Indicated Producers, California Cogeneration Council, Southern California Utility Power Pool/Imperial Irrigation District (SCUPP/IID), California Industrial Group, the City of Long Beach, the City of Vernon, Kern River Gas Transmission Company (Kern River), and Roadrunner Club Association, Inc. (Roadrunners). On many issues the interested parties share a common position and their briefs are often duplicative. In this decision, therefore, we will not always mention each party that took a position on a particular issue, but will only refer to the parties whose agreements are representative.

For the most part, only the controversial issues are discussed in this decision, but the findings of fact will include all findings required to set rates.

Both applications were consolidated for hearing before Administrative Law Judge Robert Barnett.

II. Spot Gas and Alternate Fuel Price Forecasts

The spot gas and alternate fuel price forecasts are directly relevant to both the level of core-customer rates and the forecast of gas demand by both core and noncore market segments.

There is no substantial difference between the crude oil and alternate fuel price forecasts presented in this proceeding by DRA and SoCal. SoCal has accepted DRA's forecasts, as shall we. In either case no economic fuel switching is expected. An oil price forecast of $19 per barrel for BCAP periods one and two is adopted.

SoCal has also accepted DRA's spot gas forecast of $2.01 and $1.96/MMBtu for BCAP periods one and two, respectively, but SDG&E contends that its forecast of $2.29 and $2.28/MMBtu is more accurate. The major reason for the difference in these estimates is that DRA based its estimates on average mainline prices, while SDG&E based its estimates on the California border price. In using the border price SDG&E has combined the commodity and transportation components of delivered gas at a time when transportation charges are undergoing significant changes. We have used border price comparisons frequently and acknowledge their validity, but in forecasting spot gas in this case we prefer the unbundled mainline comparison, and will adopt the DRA forecast.

SoCal has accepted DRA's single portfolio Weighted Average Cost of Gas (WACOG) forecast of $2.11/MMBtu and $2.01/MMBtu, as shall we.

III. Gas Demand

Accurate predictions of gas demand are crucial to a fair allocation of costs and to providing the utility with a fair opportunity to earn its authorized rate of return. If an unrealistically high forecast of gas demand for a particular class of customers is adopted, that customer class will be allocated an inordinately large share of the utility's revenue requirements; rates would be designed so that the allocated revenue requirement would be recovered only at the adopted level of demand. If the actual demand level is anything less, the utility will not have a fair opportunity to recover its revenue requirements from the noncore sector, which is subject only to partial balancing account treatment.

In this BCAP, gas demand forecasting has been complicated by the implementation of the Commission's Procurement Decision D.90-09-089, and by the impact of Priority 2A (P2A) "economic practicality" shifts of core customers to the noncore class under Commission Resolution G-2948 and other related decisions. The central issues concerning gas demand in this BCAP involve the noncore industrial forecast, the impact of P2A "economic practicality" shifts, service level elections by noncore customers, core aggregation and core subscription load, the Long Beach utility electric generation (UEG) demand forecast, the heat rate update from UEG customers (which is used to determine how much gas cogenerators can use under the Schedule GN-50 rate), and other issues, including anticipated discounting, which are directly relevant to a forecast of non-enhanced oil recovery (EOR) cogeneration demand.

Both SoCal and DRA have developed econometric models to forecast throughput to residential, core commercial, core industrial, and certain sectors of the noncore industrial classes of service. Under these models, demand has been forecast as a function of weather, the price of natural gas, the price of substitute fuels, and economic activity in the SoCal service area. For the core classes of service, the SoCal and DRA forecasts are extremely close. However, for the noncore classes of service, DRA's forecast exceeds that of SoCal by 6.9% in the first year and by 4.17% in the second year of the BCAP period.

With the exception of the noncore industrial market sector, SoCal accepts DRA's demand forecasts. SoCal is also in agreement with DRA on the retail UEG demand forecast with an adjustment for the Los Angeles Department of Water and Power (LADWP) in order to reflect implementation of a two-tier rate.

A. Noncore Industrial Demand Forecast

Both SoCal and DRA have forecast a reduction in noncore commercial and industrial throughput. However, the DRA forecast expects more demand than that of SoCal in both BCAP periods, by 6.9% in BCAP year one and by 4.17% in BCAP year two. The reason for the difference is the manufacturing employment forecast utilized in DRA's econometric models. While DRA utilized the March 1991 University of California at Los Angeles, Business Forecast of the California Economy, (UCLA forecast) as its source for an employment forecast, SoCal based its forecast on projections of economic conditions in the SoCal service territory which, in turn, are based upon assumptions about the U.S. economy. The employment data utilized by SoCal was from the SoCal Service Area Economic Model. The national data was taken from the Data Resource, Inc. (DRI) U.S. Model.

DRA argues that while SoCal's employment projections have the advantage of being service area-specific, DRA's employment projections are based on a more recent forecast of national and state economic conditions than SoCal's. Furthermore, since economic activity in Southern California has a large influence on the California economy, the use of a California forecast captures the bulk of economic activity in the SoCal service area.

SoCal says that DRA's argument in this regard is no longer applicable. On cross-examination, DRA's witness admitted that a more recent UCLA forecast than that used by DRA in forecasting noncore industrial demand has revised the 1992 manufacturing employment growth rate downward from 2.1% to 1.3%. As a result, DRA's argument that its forecast has the advantage of utilizing more recent information is moot. SoCal maintains, in fact, the most recent forecast by UCLA is very much in line with the forecast utilized by SoCal. It is the difference between the DRI employment forecast and the version of the UCLA employment forecast utilized by DRA which is primarily responsible for the difference between their noncore commercial and industrial demand forecasts. SoCal argues that because the employment forecast used by DRA is not service area-specific (in addition to the fact that it has been revised downward since DRA's filing in this proceeding, so as to bring it more in line with that utilized by SoCal), it renders an inaccurate picture of manufacturing growth in Southern California due to the economic differences between Northern California and Southern California. Southern California is heavily industrial compared to the rest of the state.

We agree with SoCal's assessment of manufacturing employment and will adopt it.

B. Non-EOR Cogeneration Demand

SoCal has forecast 72 MMdth of non-EOR cogeneration demand during both BCAP periods, including 8.0 MMdth for long-term transportation customers (excluding 9.0 MMdth core exchange gas customers). Industrial cogeneration volumes are projected to be 50 MMdth, while the commercial cogeneration requirements are forecast at 22 MMdth.

DRA did not take issue with the company's forecast of 72 MMdth for BCAP periods one and two. However, DRA did take issue with heat rates used to calculate the amount of gas available at the cogeneration rate. SoCal has submitted revised forecasts using the correct heat rates. These will be adopted.

TURN took issue with the forecast and recommended adjusting it upward. TURN claimed that SoCal had excluded 8 MMdth of load from the forecast which could be retained through discounting. Its witness estimated that an additional $3.6 million in revenue could be generated by retaining this load on the system through discounting. Based upon this, he proposed increasing the throughput estimate by 4.5 MMdth which is the amount of throughput at the default rate which would generate this additional revenue. DRA supports the TURN recommendation.

SoCal asserts that its forecast included discounting to retain non-EOR load. It proposed a cogeneration rate of 9¢ per therm and a discount down to 6.3¢ per therm in order to maintain the load forecast in the non-EOR cogeneration market. SoCal contends that discounting any lower will not achieve any additional demand. SoCal's forecast appears reasonable and will be adopted.

IV. Gas Supply

SoCal has stipulated to the DRA forecasts of weighted average spot prices and of the single portfolio WACOG, and there is no dispute concerning capacity assumptions, fixed gas supply costs, and other related direct billings.

There are, however, several issues which impact gas supply and are subject to considerable dispute. Among these issues are the methodology for calculation of the minimum purchase obligation (MPO) transition cost, the projected start-up date for the pipeline being constructed jointly by Kern River Mojave Pipeline Company (Kern River or Kern/Mojave), and the impact of the anticipated Transwestern Expansion.

A. Single Portfolio WACOG Forecast

DRA's WACOG forecast, after adjustment for MPO, is $2.11/Dth for BCAP year one and $2.01/Dth for BCAP year two. For the purposes of this proceeding, SoCal has accepted DRA's single portfolio WACOG forecast.

TURN criticized this forecast and speculated that it was 5% to 10% too high. We give no weight to TURN's speculation and will adopt the DRA forecast.

B. The Minimum Purchase Obligation (MPO)

MPO transition costs are excess costs incurred to satisfy minimum purchase obligations under long-term supply contracts executed before the Commission's gas industry restructuring that was implemented in May 1988. These contracts include SoCal's California, POPCO-Hondo, and Federal offshore supply contracts. The original intent of the MPO transition cost concept was that certain high-cost contracts--which neither core nor noncore ratepayers would purchase today if given the choice--would be fairly allocated between all ratepayers.

The Commission's existing method for calculating MPO costs was discussed in D.87-12-039 (26 CPUC 2d 213, 236):

> "...it appears likely that POPCO and certain California supplies will continue to be taken by the utilities under contractual provisions which would not likely be tolerated in today's competitive market. It is important to reiterate that what we consider uncompetitive is the combination of high minimum purchase obligations and higher-than-market commodity prices.
>
> "For SoCal, there are MPO-related transition costs associated with POPCO and California supplies. The POPCO and California gas supplies will all be incorporated into the core portfolio, and we are reasonably satisfied that the sum total of all other gas supplies assembled by SoCal to serve the core is a useful proxy for the competitive price of gas. This proxy is relatively stable, easy to calculate on a continuing basis, and is not based upon any particular rate design method. Because the supplies to which these transition costs are attached are a relatively small part of SoCal's overall purchases, we do not expect great swings in the calculation of these costs. Thus, the calculation avoids the concerns that led us to reject for use in this proceeding the 'bottoms-up' approach to excess gas costs."

SoCal has estimated MPO transition costs by comparing unit prices under the affected agreements with a weighted average of prices under long-term and spot purchases. This approach (the WACOG approach) was first used by the Commission in D.87-12-039, and it was most recently used in D.90-11-023.

A number of parties[1] (known as the Stipulating Parties) urge that we reconsider our method of determining MPO costs and support the recommendation of Long Beach, which would reduce the MPO transition costs for the two-year BCAP period from $41,612,000 to $12,815,000 and place the entire difference on the core customer.

A witness for Long Beach testified that MPO transition costs should be based on comparison to prices contained in long-term supply contracts, as specified by the Commission in D.86-12-010. The witness stated that MPO transition costs are a subset of "excess procurement costs." Excess procurement costs were first discussed in D.86-12-010, p. 102:

> "An accurate assessment of the extent to which procurement costs are excessive may be quite difficult. The best comparison would probably be to new long-term contracts. Absent that, another approach would be to compare them to each other (e.g., to assess any difference among commodity rates in existing long-term contracts as transition costs)."

In D.87-12-039, the Commission selected a WACOG approach in large part because SoCal did not have long-term "benchmark" contracts. The WACOG was a necessary simplification at that time and has been used since then. He said that the WACOG approach used in D.87-12-039 and D.90-11-023 should not be continued because the conditions that led the Commission to deviate from its policy in D.86-12-010 have changed. SoCal now has a substantial number of long-term contracts negotiated under the post-D.87-12-039 market

1 The Stipulating Parties consist of Edison, SDG&E, SCUPP/IID, the City of Long Beach, and the California Industrial Group, California League of Food Processors and California Manufacturers Association (CIG). These parties are all noncore users of the SoCal system. They stipulated that $160 million of costs should be transferred from the noncore to the core. We are not bound by that stipulation.

structure that can be used to determine MPO transition costs. In short, it is no longer necessary or appropriate to use the WACOG approach chosen in D.87-12-039.

He contends that MPO transition costs should reflect only those prices in excess of the upper limit of the range of prices called for in SoCal's new long-term contracts. He said that our task is to compare those contracts that are transition cost candidates with this upper limit and to assess transition costs only when the candidate prices exceed the upper limit of prices that SoCal would pay under its new long-term contracts. He calculated the MPO transition cost estimate for the two-year BCAP period to be $12,185,000 as compared to SoCal's forecast of $41,612,000. He believes it is appropriate to use the upper limit of the range because transition costs are intended to represent the excess of prices in pre-transition contracts over currently prevailing market prices. The upper limit of prices in SoCal's new long-term contracts places an upper limit on currently prevailing market prices. Thus, only prices above this upper limit should be considered excess transition costs. Using an average price is inappropriate because there is a range of prevailing market prices above and below the average price which should not be considered "excessive."

SoCal, DRA, and TURN oppose any change in the MPO calculation. TURN's witness testified that the Commission's reasoning in D.87-12-039 continues to support the use of the existing MPO calculation method. As a benchmark, the overall portfolio WACOG is still relatively stable, it is easy to calculate, and it is not based on any particular rate design method. He said that the essential purpose of the MPO is to share equitably among all customer classes the excess gas costs that would otherwise be borne solely by the core portfolio because that portfolio has served as the dumping ground for SoCal's unmarketable gas supply contracts. That reality has not changed since 1987.

Perhaps the most precise calculation of MPO costs would result from a determination of the price SoCal would pay for replacement gas if it were not required to purchase under the MPO-related contracts. SoCal's evidence indicates that in most months the price for replacement supplies would actually be lower than the forecasted WACOG. This suggests that the current method understates rather than overstates MPO-related transition costs.

He testified that Long Beach's approach is extreme and illogical. It ignores the fact that the high-cost discretionary supplies used as the benchmark are not expected to be purchased by SoCal in any month of the forecast period. In every single case SoCal could, and apparently would, displace these expensive discretionary supplies with spot gas, or less expensive gas from its other contracts. Thus, the prices that Long Beach uses are more reflective of the cost of a peaking supply than of a baseload must-take source.

He said it would be totally incorrect to exclude all spot gas supplies from the determination of the MPO benchmark as Long Beach suggests, because SoCal's market-responsive long-term contracts typically include provisions that permit at least limited substitution of spot gas without charge when spot is cheaper. Spot purchases are anticipated by and form an integral part of the contract's supply package and price. It would be a false comparison to look only at the long-term price in the contract, while ignoring the fact that the contract permits some level of spot gas substitution. SoCal's spot and contract purchases are both part of its overall contracting strategy, and both should be included in the MPO calculation. Finally, he asserted that the contract prices used by Long Beach have never been found reasonable by this Commission. Indeed, DRA has challenged several of SoCal's contracts in the latest reasonableness review. It would needlessly complicate matters to base the MPO calculation on a single contract that might ultimately be judged unreasonable. The current WACOG-based calculation avoids this potential problem.

We will make no changes in our method of allocating MPO costs. We have used the WACOG approach for four years and have found it to be simple in application and fair in allocation. The recommendation by the Stipulating Parties that we should change a simple computation for a complex analysis of contract prices and purchases has no merit. It is merely a formula to shift costs which were incurred for all customers from noncore to core. SoCal's overall WACOG of the non-MPO gas categories should continue to be used as the benchmark for the MPO calculation, inasmuch as these supplies represent the overall effectiveness of SoCal's contracting efforts and are a more accurate measure of the "excess" nature of the MPO contracts.

Certain parties have recommended that we announce a termination date for MPO costs. That is, they do not want MPO costs allocated to the noncore in future years. No reason is given except that MPO costs have been in place for a long time, and these parties are concerned that the MPO rate mechanism will become a permanent feature of rate design. Their concern is unwarranted. As soon as the contract obligations have been satisfied, the MPO rate mechanism will fall of its own weight.

C. <u>Projected Kern/Mojave Pipeline Start-up Date</u>

The date on which the Kern/Mojave pipeline comes on-line is directly relevant to forecasts of system capacity and curtailments, and demand and throughput forecasts. If the pipeline were to be operational earlier than July 1, 1992, as has been forecast by Kern River, the forecast for EOR cogeneration bypass would increase for the first BCAP period while the demand for this market would decrease. The in-service date for the Kern/Mojave pipeline will also impact forecasted curtailment. In that regard, if this pipeline were to come on-line in January of 1992, curtailment could be eliminated in the months of January and

February. In fact, under the SoCal cold year forecast, curtailment would be eliminated in a cold year beginning the time the Kern/Mojave pipeline is in operation. The adoption of an earlier on-line date for the Kern/Mojave pipeline than July 1, 1992 would impact cost allocation to all customer classes due to the additional UEG demand that could be served in a cold year.

A reasonable forecast of the anticipated date that the Kern/Mojave pipeline will be on-line is necessary to arrive at a fair cost allocation in this proceeding. SoCal and DRA have forecast July 1, 1992, while Kern River has proposed January 1, 1992. Our concern in this dispute is to be cautious. Although Kern River has shown that parts of its project are currently on schedule, the majority of pipeline segments which have been completed are located in flatlands, not the mountainous terrain which must still be traversed. Further, construction in this mountainous terrain will have to be completed in the winter, which increases the likelihood of substantial delays. Unanticipated causes for delay have already occurred since the hearings in this proceeding and are likely to occur again in the future. Because of the magnitude of this project and the difficult terrain it must cross we believe it is prudent to anticipate some delay and will adopt SoCal's in-service date of July 1, 1992 for forecast purposes.

D. Transwestern Expansion

Transwestern Pipeline Company (Transwestern) has filed to increase its mainline capacity to California by 340 MMcf/d, which is expected to be in service by January 1992. It already has firm commitments for this capacity of 200 MMcf/d from PG&E and 60 MMcf/d from other parties (which do not include SoCal). SoCal has not forecast additional throughput from Transwestern during the BCAP period.

SoCal states that it has no interconnection agreement with Transwestern, nor has it shipper commitments guaranteeing recovery of the increased facilities costs for such interconnection. It says it has no plans at this time to install any interconnection facilities except for some small enhancements which would increase its capacity to receive Transwestern gas by 50 MMcf/d.

TURN urges us to include this addition 50 MMcf/d in our estimates of gas supply available to SoCal. We shall do so. Although SoCal does not plan a major upgrade to take the Transwestern increase, its "small enhancements" will be in place and we would expect, over time, a more substantial connection if for no other reason than system security.

V. Revenue Requirements

A. Updates to Balancing and Tracking Accounts

Forecasts of balancing and tracking account over/undercollections were first presented by SoCal as of September 30, 1991 based upon recorded data as of January 31, 1991 together with forecasted data for the months between January 31, 1991 and September 30, 1991. In September updated accounts were filed based upon recorded data as of August 31, 1991 together with estimated activity for September. Only the controversial accounts are discussed in this decision. We will use the September update for BCAP rates.

B. Seasonal Rate Shortfall Account

In D.91-05-039 the Commission adopted seasonal volumetric rates for noncore retail customers. Based upon this decision, lower summer rates went into effect on August 1, 1991. However, due to the timing of the implementation date these lower summer rates have not been offset by higher winter rates based on the adopted revenues and rates from SoCal's 1990 ACAP. For this reason, our action in D.91-05-039 created a revenue shortfall which we authorized SoCal to recover through a Seasonal Rate Shortfall Account.

DRA estimates that this account will have accrued approximately $4 million by October 1, 1991. DRA recommends that the costs accrued in the account be allocated on an equal cents-per-therm basis to the retail noncore. Since the shortfall is generated as a result of the mid-term change in noncore rate design, it is appropriate that the costs remain within the noncore class. Finally, since this shortfall is a one-time phenomenon, the account should be abolished on the effective date of the BCAP decision which follows after this BCAP decision. DRA's recommendation will be adopted. We should point out that this is not retroactive ratemaking because at the time we made this change effective August 1, 1991, we also provided for the revenue shortfall.

C. <u>Brokerage Fees</u>

SoCal has in the past purchased gas for its noncore customers and incurred expenses designated as brokerage fees. Recently, SoCal's brokerage fee expense was estimated at $4.23 million annually, which SoCal estimates for this BCAP. In SoCal's most recent ACAP the noncore sales were in the range of 160 MMDth and the $4.23 million brokerage fee was recovered by charging $0.266/therm to core-elect and noncore customers. However, in D.90-09-089 we ordered that SoCal's noncore portfolio be eliminated starting August 1, 1991. This action reduced the amount of noncore sales to about 36 MMDth. If the $0.266/therm rate were spread only over this reduced amount, the brokerage fee shortfall would be approximately $3.3 million. SoCal does not propose to increase the $0.266 rate but recommends that the shortfall be allocated to core and noncore based on the adopted 1990 ACAP ratios. Further, SoCal points out that between August 1, 1991 and the time this decision becomes effective there will be a loss of noncore sales which will be only partly replaced by core subscription sales. The difference in sales results in an estimated brokerage fee shortfall of $0.43 million. SoCal proposes to recover the $0.43 million shortfall from noncore retail customers in the BCAP period on an equal cents per therm basis.

DRA disagrees with SoCal that it should be entitled to full recovery of $4.23 million. DRA argues that this base revenue requirement was adopted on the assumption of significant noncore procurement activity. SoCal has not provided a new brokerage fee study based on its new, lower, procurement activity to consider revisions to the level of expenses allocated to brokerage activities. SoCal's position is unrealistic, in DRA's opinion, because it assumes that there will be no drop in brokerage-related costs even though volumes will drop dramatically. Pending a study showing SoCal's cost of brokerage activity for core subscription, DRA believes that the most realistic approximation is to assume a drop in brokerage costs proportional to the drop in brokered volumes. As a result, DRA asserts that SoCal should not recover brokerage-related costs above the $0.266/th rate currently being charged to core-elect and noncore customers.

SoCal argues that DRA's assumption that it will be able to avoid an amount of brokerage-related expenses proportional to the drop in procurement volumes directly contradicts prior Commission decisions which determined that allocated brokerage costs be calculated on the basis of embedded, as opposed to avoided costs. For example in D.89-03-014 the Commission ruled: "We will adopt the brokerage fee policies proposed in R.88-08-018. As we stated in that order brokerage fees will be based on embedded costs." (D.89-03-014, see p. 5.) "Costs allocated to brokerage should not be limited to those which are avoidable in the short term." (D.89-09-094, Finding of Fact 5, p. 17.) And, assuming a reduction in brokerage-related expenses, it does not follow that the reduction will result in excess revenue since other expenses related to procurement implementation are likely to increase.

SoCal asserts that its base revenue requirement is authorized in its general rate case and subsequent attrition decisions. DRA is now proposing to make the level of authorized margin an issue in this cost allocation proceeding. While it would be proper for DRA to make a proposal for reallocating that amount of authorized gas margin currently allocated as "brokerage fees," it is inappropriate for DRA to propose to remove these amounts from SoCal's authorized margin. If DRA wishes to do so it must do so in SoCal's next general rate case.

Finally, SoCal explains that even if it should experience some decrease in brokerage-related expenses, it does not follow that the amount would become excess to its operational needs. It cites, for example, the $1.5 million expense for "Service and Information for Large Commercial and Industrial Customers," which is included in the current brokerage fee amount. In light of the Commission's ongoing restructuring, including the elimination of the noncore portfolio, transportation of aggregate core loads, the conducting of open seasons to determine service level and core subscription elections and the interim buy/sell arrangements, it is inconceivable, to SoCal, that anybody would argue that SoCal will experience a reduction in noncore customer information expenses.

In regard to the brokerage fee shortfall occurring between August 1 and BCAP implementation, SoCal believes it is entitled to recover this amount for the same reasons it should recover the entire brokerage fee.

PG&E supports SoCal and recommends that the brokerage revenue requirement be made subject to balancing account treatment as was done in PG&E's last ACAP, D.91-05-029. TURN supports the use of a balancing account to recover the $4.23 million revenue requirement because the fee is based on fully allocated embedded cost, not avoidable costs, but argues that the anticipated shortfall between August 1 and the effective date of this decision should not be recovered because to do so would be retroactive ratemaking.

We agree with SoCal that its brokerage fee expense should not be reduced in this BCAP merely because it will suffer a drop in noncore sales. The fees are based on embedded costs and were authorized in SoCal's general rate case. We have been given no good reason to reopen a rate case finding on one issue because of a change in operations. Of course, brokerage fees will be again reviewed in SoCal's next general rate case. We will adopt the balancing account treatment for this revenue requirement that we adopted for PG&E. The request for relief from the $0.43 million shortfall, however, is different. In that instance SoCal is seeking to make up lost revenues, which is a request for retroactive ratemaking and must be denied.

D. Interutility Transportation

Because of the new procurement rules which became effective August 1, 1991, SoCal requests an alternate mechanism for the recovery of interutility transportation fees paid by SoCal to PG&E for transportation services. Under the traditional approach, interutility costs are included with the cost of spot gas purchases and, as a result, allocated between noncore sales customers and core customers based on the extent to which the core portfolio contains purchases from the spot market. With the implementation of the procurement decision, noncore procurement is discontinued and a new rate treatment for the recovery of interutility costs is required for the BCAP period. Absent the adoption of a new treatment for recovery of these costs during the BCAP period, most of the burden associated with interutility transportation would be borne by core and core subscription customers since, with the elimination of noncore procurement, the costs of spot gas purchases will be included in the single purchased gas portfolio which will now principally serve the core market.

Both SoCal and DRA propose to consolidate interutility revenues and costs, and include the net result in transmission rates for all customer classes. DRA also generally agrees with SoCal's estimate of interutility costs and revenues during the BCAP period but projects an annual average of $3.09 million in net interutility costs compared to SoCal's projection of $3.35 million. SoCal would allocate costs on the basis of average year throughput (equal cents per therm) because interutility costs are more in the nature of variable transmission costs. From the standpoint of cost causation, each therm of throughput contributes equally to the need for using these transmission services, regardless of customer class.

SoCal is presently undercollecting the level of interutility transportation costs previously found reasonable by the Commission because of the reduction in noncore procurement services provided by SoCal beginning August 1, 1991. This undercollection will continue until a decision is rendered in this BCAP. To recover the shortfall between August 1 and the decision date, SoCal proposes that it be permitted to establish a tracking account to record interutility transportation costs incurred from August 1, 1991 through the effective date of this decision. SoCal points out, but for the arbitrary selection of August 1, 1991 by the Commission as the date for implementation of the new procurement rules, it would not have been deprived of the opportunity to fully recover the costs of interutility transportation during the test period adopted by the Commission in SoCal's last cost allocation proceeding.

As with brokerage fees, it would be impermissible retroactive ratemaking for us to authorize a tracking account to recover past costs. The only costs that can be recovered through a tracking or balancing account are those which are incurred after the account is created. (Re PG&E, D.88-09-020, pp. 18-21.) We will adopt DRA's cost estimate, which is based on DRA's slightly lower estimate of the volumes expected to move over line 300. Costs should be allocated on the basis of average year throughput (equal cents per therm).

E. Pitas Point Costs

SoCal has requested authorization to recover, both prospectively and retroactively to August 1, 1991, $752,000 in franchise fees and uncollectibles (FF&U) related to its purchase and resale of Pitas Point gas. TURN is opposed, because there is no explicit authorization for such recovery and because the request is contrary to the representations made by SoCal and its affiliates when they sought Commission approval of the Pitas Point settlement agreements with Union Oil and Texaco in 1985.

Pitas Point gas is delivered to the SoCal system by an affiliated offshore pipeline known as PIOC. Pursuant to the terms of the 1985 settlement of a lawsuit with the gas producers, Union Oil and Texaco, SoCal purchases the gas from PIOC and immediately resells it back to the producers at cost. The gas is then transported (technically "exchanged") to end use facilities owned by the producers within the SoCal service territory for a small fee. The purchase and resale of the gas to the producers triggers a franchise fee obligation, which SoCal is seeking to recover in rates from other customers.

The Pitas Point settlements were submitted to this Commission in 1985 in a series of advice letter filings--SoCal Advice Nos. 1504-1505 and PLGS Advice No. 68 (Union Oil, 4/12/85) and SoCal Advice Nos. 1525-1526 and PLGS Advice No. 69 (Texaco, 6/18/85). The advice filings were approved by Resolutions G-2638 and G-2639 (Union Oil, 6/5/85) and G-2645, G-2646, and G-2647 (Texaco, 8/7/85). No mention was made of any potential ratepayer obligation for FF&U. TURN notes that the language of the filings indicated that there would be no cost to ratepayers as a result of the transactions:

> "The effect of the Agreement for the Sale of Gas by SoCalGas to Union is a 'wash' transaction

> with respect to the cost of such gas to SoCalGas, and will have no impact on ratepayers. Therefore, SoCalGas has proposed to remove the cost of such gas and the related revenues from treatment under the Consolidated Adjustment Mechanism." (Res. G-2638, Attachment A, Sheet 3.)

The cover letter of the Texaco advice letter package contained similar language, as reflected in paragraphs 4 and 5 on page 1 of Resolution G-2646.

SoCal has been recovering Pitas Point-related FF&U through its noncore portfolio price since 1985. Now, with the elimination of that portfolio, the company wants to assign all ratepayers responsibility for these costs. TURN sees no justification for such action. It argues that either the company did not realize that these transactions would generate FF&U, in which case the costs are its own problem, or else it did know and nonetheless represented the deal as a "wash," in which case a strong rebuke is in order. In either case, ratepayers should not be held accountable for SoCal's behavior. SDG&E supports TURN.

SoCal argues that as a result of these Commission-approved Pitas Point transactions, it incurs a franchise fee obligation for volumes purchased and sold back to Union Oil and Texaco. Since the inception of the Pitas Point settlement agreement, the Commission has allowed SoCal to recover the resulting FF&U expense through every consolidated adjustment mechanism (CAM) and ACAP providing for the recovery of SoCal's revenue requirement. The FF&U cost component was recovered in rates in each of SoCal's CAM decisions since implementation of the settlement (D.85-12-106, p. 10; D.86-08-082, pp. 14, 18; D.87-01-046, p. 37). The Commission has continued to approve rate recovery of the Pitas Point FF&U costs in the last two ACAP decisions (D.90-01-015, App. B, Table 6; D.90-11-023, App. E, Table 6).

Both SoCal and DRA agree that a new means for recovery of Pitas Point FF&U must be devised for the BCAP period inasmuch as the existing methodology authorizes such costs to be recovered through the cost of gas purchased by noncore customers. However, to continue to treat the Pitas Point revenue requirement as a gas cost would require the expense to be allocated to the single gas procurement portfolio beginning August 1, 1991 and thus recovered primarily from core customers. As a result, both SoCal and DRA agree that the Pitas Point revenue requirement should be treated the same as transmission costs and allocated on that basis.

We agree that SoCal should be allowed to recover its Pitas Point FF&U expenses in the BCAP period, allocated on a transmission cost basis. TURN's argument that we should reject this expense because of its interpretation of a 1985 SoCal filing regarding a wash transaction comes much too late. The Pitas Point expense has been allowed in all SoCal proceedings since 1985 and objections could have been made much earlier. TURN was aware of this, DRA was aware of this, as were all parties over the years. At this point, the issue is settled. However, SoCal's request to recover amounts between August 1, 1991 and the effective date of this order will be denied. That request amounts to retroactive ratemaking.

F. Cogeneration Shortfall Account

SoCal requests $99,000 to compensate it for undercollections which occurred when cogenerators were billed on their "otherwise applicable tariff" at a time when that tariff was below the forecasted UEG rate. This shortfall was incurred between May 1, 1988 and January 14, 1990.

SoCal's request is denied. The issue of the cogeneration shortfall account was addressed and finally resolved in SoCal's 1989 ACAP. In that proceeding SoCal sought to recover over $14 million recorded in this account under a theory which we rejected. (D.90-01-015, pp. 73-76.) (Nor was recovery allowed in the 1990/91

ACAP (D.90-11-023).) SoCal now attempts to recover $99,000 under a new theory. SoCal cannot relitigate an issue that has been decided. Further, recovery of these dollars is now precluded by the rule against retroactive ratemaking. The 1989 ACAP decision abolished the cogeneration shortfall account. There is presently no account in which those dollars can be recorded and the Commission is precluded by law from retroactively creating such an account.

G. Amortization Period for Balancing and Tracking Accounts

In its initial filing in this proceeding, SoCal reflected a 24-month amortization period for balancing accounts and a 12-month amortization period for tracking accounts. DRA states that because the forecasted cost of gas is decreasing, an opportunity now exists to amortize the large net balancing account undercollections in 12 months without causing a significant impact on rates. DRA asserts under these circumstances it is possible to zero out these balancing accounts and still achieve an overall rate reduction for the forecast period. This, in turn, will contribute to core rate stability and will provide a cushion against future potential undercollections. SoCal agrees. We will adopt DRA's recommendation.

H. Storage Banking Revenue

The pilot storage banking program has been extended for an additional year, pursuant to Resolution G-2973; therefore, the forecasted storage banking revenue credit of $4.5 million has been removed from the revenue requirement.

VI. Cost Allocation

A. Administrative and General

SoCal has presented two methods to allocate costs between customer classes. One method is in compliance with past Commission decisions and the alternate is based on a proposal which SoCal and its noncore customers assert is more closely aligned to cost of service. SoCal believes that its alternate proposal is more equitable and will allow SoCal to compete more effectively in an increasingly open marketplace with the numerous low-cost bypass opportunities being offered to SoCal's customers.

DRA and TURN object to SoCal's alternate proposal. DRA contends that the cost allocation methodology employed by the Commission since 1986 has remained substantially intact until today, but in this proceeding it has been attacked with a vengeance by noncore and wholesale customer interests intent upon shifting in excess of $150 million in fixed costs permanently onto the backs of residential and commercial customers. Under DRA's computation, if implemented in their entirety these proposals would reduce noncore transportation rates by over 30% and wholesale rates by almost 15%, while increasing core transportation rates by 10%.

SoCal's alternate proposal would change the manner in which a number of different costs are allocated, including the EOR revenue credit, administrative and general (A&G) costs, distribution costs, lost and unaccounted for (LUAF) gas costs, MPO transition costs, and UEG igniter fuel costs. There are also several proposals to unbundle interstate demand charges thereby shifting significant additional costs onto core customers. The impact of these proposals is set forth in the following table, as estimated by DRA.

Incremental Revenue Effects of Proposed
Allocation Changes on Core Customers

Cost Allocation Proposals Add to Revenue Obligation of Core	Impact on Core $ Millions/Yr.
A. A&G to 84% Operations/16% Throughput	$ 44.99
B. LUAF to Distribution Load Only	11.14
C. Distribution Allocated on Peak Hour Load	23.63
D. Igniter Fuel to Noncore UEG Rate	6.72
E. EOR Rev. Credited to Transmission Only	16.42
F. Unbundle Interstate Demand Chg.*	48.00
G. MPO Calculated on Basis of Most Expensive Gas Under Long-term Contracts**	8.34
Net Revenue Changes	$159.24

* This is the worst case analysis.

** This represents the total annual dollar impact on the core portfolio.

DRA strenuously objects to our considering any change in cost allocation procedures in this BCAP. It asserts that the major and precedent-setting changes proposed by the parties should only be undertaken as part of a general and comprehensive review which considers marginal cost-based rates for all of California's gas utilities. These issues shall be deferred to the Long-Run Marginal Cost (LRMC) proceeding, I.86-06-005. The Commission has made substantial progress in moving toward a rate structure based upon marginal costs and it should not be sidetracked by the proposals in this proceeding to alter the existing embedded cost allocators. The utilities have already performed the marginal cost studies ordered by the restructuring decisions. The studies have been the subject of lengthy workshops and, based upon these workshops, the Commission has adopted a set of guidelines for estimating marginal costs. (D.90-07-055.) It is only within the context of a generic cost allocation proceeding that major revisions to the existing methodology should be considered.

DRA notes a number of problems with addressing significant cost allocation issues in this proceeding. Two of the utilities' major cost components are operations and maintenance (O&M) and A&G expenses. In prior proceedings, the same load patterns were used to allocate functionalized plant, O&M, and A&G. Now that there are proposals which would use a more extreme load pattern for both A&G and distribution-related costs, of which O&M is a major component, the issue of how these costs relate to the need for new plant becomes critical. However, the current allocators for O&M and A&G have still not been examined. Another issue which has yet to be examined is whether the transmission system, which is largely depreciated in comparison to the distribution system, is undervalued when embedded costs are used to set rates. DRA believes these issues should be examined in a generic fashion before the existing methodology is substantially altered.

Given the expedited nature of the BCAP schedule and the lack of advance notice that this was to be a cost allocation policy proceeding, DRA says there was no time for it to address substantial changes in allocations that would benefit core ratepayers. Consideration of these issues, in DRA's opinion, would likely reduce the rates of small distribution customers relative to large transmission level customers in direct contrast to the proposals put forth by noncore and wholesale interests. DRA submits that it simply is not fair to core ratepayers to address cost allocation revisions in such a piecemeal fashion. DRA recommends that, for the purposes of this proceeding, the only cost allocation changes which should be addressed are those which either flow out of existing cost allocation principles or are needed to conform the cost allocation to new decisions. Only three items fall into these categories: (1) the transfer of igniter fuel service from core to noncore status; (2) the direct assignment of UEG customer costs to correct a prior oversight; and (3) the calculation of default rates on the basis of demand rather than throughput to reflect the new service level structure which went into effect on August 1. These adjustments would have a relatively minor impact. The net effect would be a $5 million increase in costs allocated to the core.

DRA's argument is not completely persuasive in regard to A&G expenses. In the event a clear and relatively complete study could be presented which provided a high level of confidence in its results, we would consider reallocation at this time. We knew in 1986 that a reallocation might be necessary and that we would reconsider the question when better information became available. (D.86-12-009, p. 26; D.87-05-046, pp. 24-25.) This was the purpose of allowing SoCal's study into evidence in this case. Given the difficulties discussed below we do not believe this is the appropriate time to consider a new method of allocating A&G expenses. We agree with DRA that it will be more thorough to review this issue in our LRMC investigation. While we can also agree with the proponents of the study that five years is a long time to wait, our LRMC investigation is moving forward and can most expeditiously handle this matter.

We believe an explanation of why we cannot accept SoCal's A&G proposal at this time is in order.

SoCal argues that its A&G study is responsive to our directive in D.87-05-046 to "do a detailed study of the major cost components of the various A&G subaccounts, including a functionalization and classification of these costs" (24 CPUC 2d 231, 245). SoCal requests that the Commission digest the study in phases, with the first bite, a shift to a 65/35 A&G functionalization ratio, to be taken in this BCAP.

In their June 28, 1991 stipulation on BCAP cost allocation issues, several parties strongly endorsed SoCal's A&G study, but objected to SoCal's phase-in proposal, recommending instead full implementation of the study in this BCAP. Were the Commission to adopt this recommendation, the A&G functionalization ratio would immediately change from the current 50/50 split to the 84/16 breakdown derived in SoCal's study. The stipulation parties include Edison, SDG&E, SCUPP/IID, Long Beach, and CIG/CLFP/CMA.

We are sympathetic to the arguments raised by SoCal and the stipulation parties that the "temporary" 50/50 A&G compromise adopted in D.86-12-009 should not become a permanent fixture of our cost allocation methodology, and that a more refined approach is badly needed.

Unfortunately, the SoCal study lacks the proper evidentiary foundation for making any change in the 50/50 compromise at this time. Both TURN and DRA presented a number of claimed defects of the A&G study. While we do not endorse all of their criticisms, it is necessary for us to elaborate on several of the defects of SoCal's study with which we do agree.

SoCal's study begins with a first round functionalization of costs. The problem is that the first-round functionalization is fatally flawed. Both TURN and DRA have noted the aggregation error inherent in defining the vague category "Operational" without first building it up from its disaggregated constituents (i.e., transmission, distribution, and storage). As TURN demonstrated in Exhibit 55 and summarized in its brief, "the breakdown into operational versus other says virtually nothing about the manner in which the associated costs should be allocated" (Exhibit 55, Page 6; TURN Opening Brief, Page 11). Without guidelines defining what is meant by "operational" and "other" the respondents to SoCal's survey are only guessing in response to the questions.

While some areas of the company may have a feel for what is meant by operational, others, or may have entirely different ideas of what the term means. This is not a sound manner to gather information useful in making substantial changes to cost allocation methodology.

Here, we must note DRA's terse conclusion that the study's aggregation problem "raises the very serious question of whether expenses that cannot be classified into the specific operational functions can in fact be classified as 'operational' at all," is particularly compelling (DRA Opening Brief, Page 9). If SoCal can not explain what is operational, how can it determine what costs should be allocated as operational.

We also agree with TURN's critique of the study's inevitable dependence upon the assumption that "A&G follows O&M," an assumption which D.86-12-009 rejected in the absence of supporting evidence (22 CPUC 2d 444, 462). SoCal simply assumed that A&G followed O&M for purposes of allocating the amorphous "operational" category of costs. SoCal did not functionalize this information as required by our prior order. Presentation of a study based on a methodology directly contrary to Commission directive can be given no weight in our proceedings, let alone be the basis for making significant changes in cost allocation proceedings.

Most persuasive is TURN's critique of SoCal's very objectivity in performing its cost study. In reference to a SoCal internal memorandum, Mr. Florio testified:

> "Remarkably, this memo -- which is supposed to be seeking objective information -- actually states the result that the study is expected to produce:
>
> "We still expect to find that A&G expenses are closely related to the size of our workforce which is predominantly 'operational'." (TURN Brief, Page 13.)

We do not attribute this memo soliciting the end result as an act of bad faith. However, it casts such doubts about the value of this study that we believe it is impossible to give it any weight in our consideration of cost allocation.

SoCal clearly has not satisfied D.87-05-046's directive to functionalize and classify A&G costs. We therefore do not have sufficient reason to move away from the original 50/50 compromise at this time even though we believe some movement may be warranted. We refuse to make that movement to increase the amount of A&G allocated to the core based upon a flawed and biased methodology. We also believe that any relief to the non-core would be infinitesimal, especially for small users. This is because any reduced allocation would be distributed on a volumetric basis, and large users (e.g., the Stipulating Parties) would receive most of the reduction. It is possible that small users would see at most a few dollars a month in reduced gas utility costs. Such a small level of relief is not a compelling reason to override the serious concerns we have with the study.

However, because of the disappointment which we believe this change from the ALJ Proposed Decision will create, we wish to further elaborate on our reasons, and our expectations. We believe that the LRMC proceeding is the proper place to decide this issue, and we are committed to to so. It was our intention in creating the Annual Cost Allocation Proceeding, which has become the Biennial Cost Allocation Proceeding, that a simplified process would be created with a minimum of contentious issues. To preserve this streamlined process we have consistently refused to revisit major changes in our cost allocation methodologies in these ACAP/BCAP proceedings, referring these issues to the Long Run Marginal Cost proceeding. We believe it would be a poor precedent to begin to litigate major changes in cost allocation in BCAPs because the current tight schedules for these cases can not be expanded with a reasonable expectation of timely decisions.

Indeed, the PG&E BCAP, which has just been filed, would likely become a replica of the LRMC proceeding with many competing studies and showings directed at major shifts of costs should we venture onto that path.

We understand and share the concern that the LRMC proceeding has been slow in coming to fruition. We must note that part of the reason for the delays in the LRMC has been a desire of the parties to focus upon other issues which were more pressing at the time rather than spread their own limited resources too thinly across several major proceedings. These parties must accept their share of the responsibility for the delays of the LRMC proceeding.

We agree that the 50/50 split was made five years ago based upon rough estimation but SoCal's study has not met our decisional criteria to enable us to make a more concrete determination based upon the record before us. We are committed to rapidly resolving the LRMC proceeding based upon a careful examination of cost responsibility on a thorough record embracing all allocation issues, rather than making piecemeal changes in a variety of proceedings.

A decision will be issued in the LRMC proceeding during the 1992 calendar year. Testimony is due to be filed in January, 1992, with hearings to commence thereafter. A schedule will be enforced calling for an ALJ Proposed Decision which can be acted upon in December. We will meet this schedule barring unforeseen delays. We believe today's decision will properly focus the efforts of the affected parties upon that case and provide the correct incentive to expeditiously resolve that proceeding.

B. <u>Common Distribution Costs</u>

The current cost allocation factor for common distribution expenses is based on noncoincident peak month throughput to customers served off the distribution system in a design cold year, an allocation authorized in D.86-12-009. Under this methodology, SoCal allocates 87% of distribution costs to the core and 13% to noncore. SoCal believes that this approach should be updated to more accurately reflect the way distribution costs are incurred on SoCal's system. SoCal claims its distribution system is designed to deliver the design peak hour load for core customers and the coincident hour load for noncore distribution-served customers. In support of this recommendation SoCal presented a study which concludes that the design peak hour volume for core customers for 1991 is estimated to be 216.1 MMcf, representing an allocation to the core segment of 93.05%, which has been reduced to 92.19% to reflect the migration of P2A volumes from core to noncore.

DRA and TURN disagree with SoCal's proposal. They argue, in the first place, the company's recommended method does not appear to accurately reflect system design criteria. The evidence shows that SoCal builds its distribution facilities to serve the maximum expected load of each noncore customer regardless of what time of the year that occurs. This means that even if cost allocation were to be based solely on design criteria, which it is not, the SoCal study has failed to measure the criteria for noncore customers correctly, because there is no particular relationship between the maximum individual demand of noncore customers and their coincident demand at the time of peak core usage. SoCal has performed no studies of the diversity of peak demands on its distribution system that would support any other conclusion.

DRA and TURN point out that while SoCal has sometimes curtailed its noncore customers because of inadequate transmission or storage capacity, SoCal's witness did not know of a single instance in which noncore customers were curtailed specifically because of inadequacy of the distribution system. The witness stated that even with the increased emphasis on firm service for the noncore market, SoCal will not need to make any changes in its traditional distribution planning criteria. Therefore, an allocation proposal such as SoCal's, which looks only at noncore demand at the time of system peak, will fail to capture the full responsibility of the noncore for distribution system costs.

Finally, DRA argues that it is inappropriate to consider SoCal's distribution cost reallocation proposal in this proceeding. SoCal singles out distribution costs for a new allocation method, while ignoring other system costs, such as transmission and storage systems. Peak-day and hourly loads may, in part, drive storage sendout requirements. Furthermore, some analysts believe that transmission and storage can be substituted for each other. Thus, it is reasonable to expect that a comprehensive evaluation of the load assumption might also have an impact on the allocation of transmission and storage costs. The appropriate place to evaluate this issue is the LRMC proceeding.

We agree with DRA and TURN. No one has ever been curtailed because of the inadequacy of the distribution system. SoCal's testimony on how it has designed its system is not persuasive. That "design" has not been tested and may never be tested. Whether the design is for the coldest day in 60 years as TURN believes, or the coldest in 35 years as SoCal claims, the fact is that there have been no curtailments because of lack of distribution system capacity. In an average year the noncore receives over 45% of total throughput but only pays 13% of distribution costs. There is no reason to change the allocation more favorably to the noncore.

C. <u>Marketing/Conservation Costs</u>

The costs incurred by SoCal's Market Services Department (which includes conservation), which amount to over $64.5 million per year, are currently classified as customer-related and allocated based upon the number of customers in each class, weighted by undepreciated distribution plant. Under this allocation core ratepayers bear over 98% of these marketing and conservation-related costs. TURN and DRA argue that a 98% allocation is unreasonable and recommend that those costs be allocated on a cents-per-therm basis. TURN points out that this Commission has held that marketing and conservation costs are not customer-related. (D.86-08-083, p. 51.) TURN acknowledges that as to SoCal these costs have been allocated on a customer-related basis and allocated 98% to the core, but urges us to reconsider this position.

TURN proposes that conservation and marketing costs be classified as commodity-related rather than customer-related, and allocated on an equal cents-per-therm basis (average year throughput) to all customer classes. SoCal's marketing budget includes energy conservation programs, fuel substitution programs, and load retention programs, as well as customer information programs and other supporting activities. TURN quotes SoCal President Warren Mitchell in his testimony in the company's last general rate case: "While the programs have been categorized differently, they have the same goal: efficient use of our energy resources." TURN points out that in D.91-07-017 and D.91-07-018, this Commission found that the costs of PG&E's and SDG&E's natural gas vehicles (NGV) programs should be allocated on an equal cents-per-therm basis because such programs benefit all customers, even though residential consumers are unlikely to be able to participate directly. TURN contends that if residential customers are required to pay for NGV programs in which they do not participate, then other ratepayer classes should help to pay for SoCal's market services programs, regardless of the extent of their participation in such programs. This Commission also recognized the principle that all customers should make a contribution to the costs of socially beneficial programs when it allocated the expenses of SoCal's Women and Minority-owned Business Enterprises (WMBE) program to all classes on an equal cents-per-therm basis (D.90-11-023, pp. 35-37). Certainly efficient use of energy and the resulting environmental improvements are important social goals, comparable to equal economic opportunity. DRA supports

TURN. TURN estimates that by adopting its position on conservation the direct effect is a shift of $33.8 million in marketing costs out of the core class: $23.5 million to noncore and $10.3 million to wholesale. SoCal estimates the shift to be $47 million.

SoCal asserts that TURN is resurrecting issues already "permanently put to rest by the Commission." But, in any case, it says that all of SoCal's conservation programs are intended to help residential and other core customers save energy and use natural gas in the most cost-effective and efficient manner. These conservation programs are directed exclusively at the core market and structured to meet the unique needs of each utility's service area. Conservation program expenditures generally reflect the number of homes in the service territory and are thus closely related in magnitude to the number of core customers served, not system throughput. SoCal cites our demand side management decision (D.90-08-068, p. 20) to the effect that conservation costs should be allocated solely to core customers.

TURN's proposal will not be adopted. TURN has apparently culled a number of statements from our decisions over the years to the effect that everyone benefits from conservation and therefore everyone should pay for conservation programs. While TURN's quotations are accurate their applicability to this proceeding is slight. More to the point is that this Commission has held in prior SoCal allocation proceedings that the core customer is to bear 98% of the costs of SoCal's market service expenses and TURN has presented no study upon which to base a change. TURN has argued that a change should be made but the facts to support its argument are lacking. If we are to change the 98% allocation factor, that change must be made on a more substantial record than has been presented here.

D. <u>Demand vs. Throughput-Based Allocators</u>

Costs are currently allocated to the different customer classes on the basis of estimated throughput rather than demand.

Under this approach, customers that are expected to be curtailed are allocated fewer costs and receive lower rates than would otherwise be the case. DRA and TURN assert that continuation of this practice is inconsistent with the new value of service type of rate structure that went into place on August 1.

As they explain, the existing cost allocation, which is largely driven by cold year allocators, automatically includes a curtailment-related cost reduction to the default rates of the customer classes most likely to be curtailed. Under the new transportation program, customers who choose interruptible service will automatically receive a rate lower than the default rate. This is because the revenues generated by the 1.2 cents/therm surcharge paid by firm customers will be credited back to the interruptible rates. The larger the firm elections, the lower the interruptible default rates. Under this structure, TURN and DRA claim there is absolutely no need to forecast cold year curtailments for cost allocation purposes. The curtailment issue is instead addressed directly through the rate design and customer choice. In their opinion, continuation of the present practice is likely to result in low priority customers receiving a double benefit: a reduction in the default rate through the cost allocation and another reduction in the default rate through the surcharge credit.

To eliminate this double benefit TURN and DRA propose that costs be allocated to customers on the basis of cold year demand rather than the current method of cold year throughput. They contend that the effect of this change would shift approximately $500,000 from the core to the noncore and is important for two reasons. First, it would make the cost allocation consistent with the revised transportation program. Second, it would simplify the cost allocation process by eliminating the need to forecast cold year curtailments.

SoCal opposes and argues that the practical effect of the DRA and TURN proposal would be to increase UEG and cogeneration rates with the rates to other customers being reduced and core customers receiving most of the benefits, which it estimates at $2 million. To shift costs from the noncore to the core, however, would be inconsistent with the Commission's intention in the procurement rulemaking to establish a system of service level surcharges and credits which would be revenue neutral between the two classes of customers (D.90-09-089, p. 45; Re Gas Procurement, 27 CPUC 2d 583, 608). In that case, the Commission expressly provided that noncore customers alone would pay the Service Level 2 surcharges and noncore Service Level 3/5 customers alone would receive the credits which accumulate as a result.

SoCal says that DRA's argument that UEG customers, since they will receive service level credits under the new procurement rules effective August 1, can now be subjected to an increase in their base rates by means of a new allocation methodology, is simply attempting to do indirectly that which the Commission has already said may not be done directly, that is, divert the benefits attributable to the service level discount from the noncore to the core. SoCal maintains that DRA's proposal effectively transfers to core customers a substantial share of the service level discount which the Commission has already determined should be reserved only for those noncore customers who elect to be served on an interruptible basis.

We agree with SoCal. The firm service surcharge and the interruptible credit amount to a redistribution of dollars within the noncore market based on the service level elections of noncore customers. The proposal of DRA and TURN would shift additional costs from the core market to the noncore market. If such a shift is reasonable it cannot be merely on the basis that some noncore customers are willing to pay extra for firm service. That issue was dealt with in D.90-09-089 where we allocated those surcharge dollars to the lower service levels. DRA and TURN have provided no good reason to depart from our current policy of allocating on estimated throughput.

E. Noncore Status for P2A Customers

Pursuant to Resolution G-2948, approximately 130 P2A customers with a collective annual demand of approximately 6.0 billion cubic feet (bcf) have notified SoCal prior to the August 1, 1991 deadline of their desire to become noncore customers and have provided information intended to satisfy the economic practicality condition imposed by Resolution G-2948. These applications have been submitted to the Commission and are pending approval. As a result, SoCal has reclassified these volumes as noncore for cost allocation and rate design.

The issue has arisen whether it is feasible to attempt to implement the impact in this BCAP period of those customers who make such elections following the initial August 1, 1991 deadline. SoCal says that the practical problems involved in swiftly incorporating these changes into the BCAP forecasts are not insignificant. The timing of BCAP hearings makes it impossible to prepare an accurate list or forecast of volumes of those customers electing a change in status from core to noncore. Without an accurate forecast, it is not possible to implement the resolution without serious risk of shortfalls or windfalls to either the ratepayer or the utility.

SoCal proposes that BCAP rates be implemented on the basis that all currently forecasted P2A volumes, with the exception of those that have already applied for noncore status through the economic practicality process, will remain in the core market cost allocation.[2] After BCAP implementation, the revenues from P2A customers who seek and actually transfer to noncore status after the August 1, 1991 deadline would be monitored separately, with SoCal booking those revenues to the Core Fixed Costs Account (CFCA). SoCal proposes that in SoCal's next cost allocation opportunity, the appropriate allocations would be incorporated into rates. This proposal, in SoCal's opinion, would ensure that core customers would not suffer a shortfall in the CFCA simply because additional migration of P2A customers was not anticipated or provided for in the 1991 BCAP cost allocation process and that Socal and noncore customers would reap no windfall as the alternative consequence of booking the migratory revenues into the Noncore Fixed Cost Account.

TURN proposes an additional tracking subaccount (within the CFCA) in order to record the difference between the actual revenue paid by P2A customers transferring to noncore status after August 1, 1991, and the revenue which would have been received had these customers continued to be billed at core rates. This revenue shortfall could then be allocated equitably in the next BCAP to all customers. SoCal believes that TURN's concerns are unwarranted and that its proposal for sub-account tracking of the P2A shortfall is unnecessary. SoCal argues that the migration of P2A customers to noncore status does not signal an avoidance of properly allocated costs, but simply reflects the reality that the CFCA migration shortfall is caused by terminating the subsidization of other core customers by P2A customers, a result contemplated by the

2 SoCal supports DRA's proposal for a tracking account to monitor revenues from P2A customers who applied for noncore status prior to August 1, 1991 and who were assigned noncore status for cost allocation purposes in this BCAP, but who subsequently fail to satisfy the Commission's economic practicality test.

Commission's earlier determination that core rates should be equalized regardless of allocated costs.

Because the need for a tracking account is supported by SoCal, DRA, and TURN our only concern is the form it will take. We believe TURN's proposal is the most conservative as it protects the core; it will be adopted. In adopting this treatment for P2A core/noncore transfers, there is no further need to hold in abeyance the processing of transfer applications received subsequent to the temporary August 1, 1991 deadline specified in Resolution G-2948.

F. Interstate Pipeline Demand Charges (The Double Demand Charge)

SoCal pays demand and reservation charges to the interstate pipeline companies with which it has service agreements for firm transmission capacity rights for either sales or transportation services. Those costs are included as a part of the company's nongas revenue requirement and are allocated to the various customer classes using the annual cold year throughput allocator. The resulting sharing of revenue requirement forms the basis for setting retail and wholesale transportation and sales rates. Under the current rate setting mechanism, a customer must pay for, in its intrastate transportation rates, a portion of these interstate pipeline demand and reservation charges whether or not SoCal actually utilizes its interstate rights on behalf of that customer.

Now that rates have been unbundled and the noncore customer can purchase its own gas to be transported over the interstate system to the California border and over the intrastate system by SoCal to its destination, the noncore customer will pay the interstate pipeline (e.g., Kern River or El Paso Natural Gas Company (El Paso)) a reservation fee, plus other costs, associated with transporting their gas in interstate commerce. Some of those customers will take delivery directly from the interstate pipeline, i.e., Kern River, and will not incur additional pipeline costs. Other customers will require SoCal's pipeline to deliver the gas. If SoCal's intrastate rate includes any of SoCal's interstate demand charges, then the noncore transportation customers will be paying two demand charges: (1) the demand charge it incurs for its own interstate service and (2) a portion of SoCal's interstate demand charges which are included in SoCal's intrastate transportation rate.

The Indicated Producers,[3] Kern River,[4] and Edison, among others, think this is unfair, while DRA thinks the double demand charge is appropriate for shippers over Kern River but not for shippers over El Paso. Many of these companies own interests in, or are affiliates of, interstate pipelines. For example, Amoco owns Amoco Altamont Company, which owns an interest in the proposed Altamont Gas Transmission System; Meridian Oil is an affiliate of El Paso; Texaco and Union Pacific own an interest in Point Arguello Natural Gas Line Company.

1. <u>Ratemaking</u>

Our regulatory process is intended to simulate a competitive market (D.89-01-040, p. 15). One of our most recent attempts to simulate a competitive market is in I.88-12-027, our investigation into the need for additional interstate natural gas

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3 The Indicated Producers are Amoco Production Company (Amoco), ARCO Oil and Gas Company, Chevron U.S.A. Inc., Conoco Inc., Mobil Natural Gas Inc., Meridian Oil Inc. (Meridian Oil), Texaco Inc., (Texaco), Union Pacific Resources Company (Union Pacific), and Unocal Corporation. These companies are both marketers and consumers of natural gas in SoCal's service area and as such are interested in the development of cost-based rates.

4 Kern River is a joint partnership between Williams Brothers and Tenneco. Tenneco is not a producer of natural gas. Williams Brothers is a conglomerate which includes both gas producers and shippers.

pipeline capacity. In that investigation we issued D.90-02-016 in which we encouraged the construction of new interstate pipelines to serve the California market. We found a near-term need for at least an additional 900 MMcf/d of natural gas and for significantly more in the long term. And we said we believed that the local distribution carriers (LDCs) represent a viable and competitive means of service.

We were emphatic in our discussion and findings regarding the benefits of new pipelines and their effect on competition. We said:

> "Additional pipeline capacity will not only satisfy the need for natural gas but also will provide an enhanced level of transportation service to noncore customers; will access new gas production areas; will secure price and supply on a long-term basis; and will permit gas-on-gas and pipeline-on-pipeline competition." (At p. 116.)

* * *

> "We will not announce a position on cost reallocation at this time. To reallocate costs at this time or to announce a position on reallocation of costs would be to subsidize new production areas and new producers. Under the current system of netback pricing there is every reason to believe that new gas producers will absorb the costs of the new pipelines. Producers are prepared to netback all of the new pipeline demand charges in the cost of gas at the wellhead in order to be able to sell gas at competitive prices into the Southern California market." (At p. 117.)

The noncore shippers and their supporters who have presented evidence in this proceeding would have us renounce our position regarding competition before the competition starts. They seek a bonus for leaving SoCal's system. They argue that they should not have to pay a "double demand charge" and that SoCal should remit the demand charge to them - either dollar for dollar as DRA recommends or as a reduction in intrastate transportation rates as Kern River and the Indicated Producers recommend. Of course, these shippers do not have to pay this so-called double demand charge; they can take service from SoCal. To the extent that they do not take service from SoCal it is a result of their own choice. Competitive forces have shown those shippers that under current economic conditions it is better for them to buy gas directly from producers and ship it over interstate pipelines to the California border. Whether it is better because it is cheaper, or more efficient, or more reliable we do not know, but whatever the reason the shippers made a competitive choice. They are not in need of a subsidy from SoCal's core customers.

But, they argue, competition is not the issue. They say that by paying SoCal's interstate demand charge in the intrastate rate they are paying a charge that they did not cause to be incurred. They cite the principle that those who incur a cost should pay the cost. This, of course, is a principle that only a regulator can understand. In unregulated industry sellers charge market rates and care little about the costs of buyers.

We have held on numerous occasions that rates should be cost based and for the most part there was a coincidence of cost between the utility and the customers; that is, the cost to the utility was incurred by the customer or group of customers who pay the rates which include the cost. As the means of allocating costs have become more sophisticated and the functions of the utility have become unbundled, customer groupings have changed and subgroups have emerged. Where once we had residential and industrial, we now have core and noncore. And we have those who take service at the distribution level and those who take at the transmission level. To a degree, the costs of serving those customers differ and rates based on those costs differ. Because of these differences the noncore customer, and subgroups within the noncore, such as EOR customers, have sought to show that as a group they did not incur certain costs of the utility and therefore should not have those costs included in the utility's rates for service to the subgroup. Those customers have begun to equate "cost of service-based rates" with "just and reasonable" rates. The equation is flawed.

Our past decisions have never held that just and reasonable rates, the statutory standard (Public Utilities (PU) Code §§ 451 and 728), had only one component - costs. We have always held that factors such as conservation, affordability, market price, and equity had to be factored into the rates. Cases which most strongly supported cost-based rates invariably tempered those statements with language which showed our concern for other ratemaking factors. In Re Rate Design for Unbundled Gas Utility Service (D.87-12-039) 26 CPUC 2d 213 we said, "In deciding both which costs to use and how to allocate them, we have exercised our best judgment based on our ratemaking philosophy and the expert testimony we have received." (At p. 228, emphasis in the original.) To the argument that we should not use a "value of service" criterion for ratemaking, we answered "the fact that we find the concept of benefits received useful in cost allocation in no way contradicts our continuing commitment to cost-based rates." (At p. 228.) Those comments were no more than a reaffirmation of the truism that there is more to ratemaking than determining costs. In Re Rate Design for Unbundled Gas Utility Service (D.86-12-009) 22 CPUC 2d 444 we said, "Economic efficiency is, of course, not the sole consideration in our choice of a revenue requirement reconciliation methodology. Equity considerations remain paramount." (At p. 457, emphasis added.) "...[F]airness would be ill-served by an approach that ultimately resulted in higher rates for precisely those customers whom we sought to protect." (At p. 457.) And we have held that setting rates for the noncore on the basis of embedded costs could be self-defeating if the rates were too high to attract traffic (D.87-05-046, p. 19).

As recently as September 1990 in D.90-09-089 we endorsed value-of-service rates when we authorized noncore customers to elect Service Level 2, to obtain firm service, by paying a surcharge of 1.2 cents/therm. And in this BCAP we have allocated that 1.2 cents to lower service level noncore customers. Neither the surcharge nor the credit has any relevance toward cost of service, but has every indicia of value of service. EOR rates are based on value of service, as are contracts with rates which are below tariff rates and which are entered into to prevent bypass of the system.

A reading of the PU Code leaves no doubt that the Commission must look beyond costs when setting rates. The principal rate sections of the Code, §§ 451 and 728, refer to "just and reasonable rates." There is nothing in the Code which equates cost-based rates as being a synonym for just and reasonable rates, or as the sole standard by which rates are considered just and reasonable. One Code section which discusses cost-based rates also requires the consideration of affordability and conservation. (PU Code § 739.6: "The Commission shall establish rates using cost allocation principles that fairly and reasonably assign to different customer classes the costs of providing service to those customers classes, consistent with the policies of affordability and conservation.") The clearest Code section which incorporates a policy other than cost as a basis for setting rates is § 454.4 which provides that cogeneration customers shall pay the same rates for gas as UEG customers. This parity statute has caused us to set the cogeneration rate to recover costs to serve cogenerators approximately $10,000,000 per year lower than it would be if rates were set on a cost-of-service basis. (See also §§ 785 and 785.7 which require us to set rates for the transportation of intrastate gas equal to rates set for the transportation of gas from any other source.) Other statutory deviations from cost-of-service ratemaking include § 739(a) (baseline rates with special consideration for persons with serious health problems); § 739(f) (to promote conservation); § 739(g) (low income customer assistance); § 735 (subsidies for natural gas vehicles); and § 783, (restrictions on line extensions). A careful reading of the Code will show more exceptions to cost-based ratemaking and more reasons why ratemaking is an exercise in judgment and not the result of a computer printout.

Nor is ratemaking just an intellectual exercise. This Commission is concerned with the effects of its policies. It is counterproductive to keep noncore rates high if the result will be bypass of the LDC system or, what is worse, a barrier to entry to new business in California. Regardless of cost allocation theory, if rates must be dropped to hold customers who contribute to margin then rates should be dropped. We do this for EOR customers and for others on a case-by-case basis and will continue to do so. But there is no evidence of an incipient exodus of noncore customers from SoCal's system, nor is there evidence that high gas rates are preventing expansion of business or creating a barrier to entry of business. The experts who testified in favor of shifting costs to the core spoke only in generalities about effects on business. The Commission has always granted exceptions to tariffed rates when circumstances warranted, and has changed its policies on cost allocation when circumstances warranted. We shall continue to do so.

We have taken a great deal of time to explain what to us is obvious in ratemaking because apparently many of the parties in this proceeding have either forgotten those principles or chose to ignore them. Every witness who testified on shifting costs to the core spoke only of cost causation, never about conservation or affordability or equity or the contradiction between their testimony and statutes such as cogenerator parity. Perhaps they believe that it is proper for the legislature to deviate from cost-based ratemaking, but improper for this Commission to do so. The money involved is substantial. Under SoCal's proposal rates will be reduced by about $210 million overall, with a $235 million reduction to the core customers and a $25 million increase to the noncore. With the reallocation recommended by the noncore representatives the reduction would be more like $25 million to the core and $180 million to the noncore. The noncore parties obviously believe the time is ripe for a massive dumping of costs on the core customer because no increase in core rates will result. What they ignore, among other things, is that a large part of the reduction in rates results from an overcollection in the gas balancing account because core customers have been paying, and continue to pay, rates based on gas prices which were projected significantly above actual prices.

The noncore customers also ignore the fact that SoCal is not a pipeline company, but an integrated company that buys, transports, stores, and sells natural gas. It cannot be broken down into constituent parts as if each part of the company could stand on its own. It certainly does not have two pipelines - one to carry interstate gas and one to carry intrastate gas, as the cost allocation recommendations of some parties would have us believe. All classes of customers of the system benefit because all other classes use the system.

2. <u>Indicated Producers</u>

The Indicated Producers argue that there is no justification today for the allocation of pipeline demand and reservation charges to all transportation rates. First, the noncore transportation customers no longer benefit from the utility's rights for gas transportation or gas purchases. Under the current regulatory structure the noncore transportation customer will receive little or no service that employs the utility's interstate capacity rights. Since the Commission has eliminated the noncore portfolio, effective August 1991, the noncore customers can obtain procurement service only by electing to the core portfolio or through using utility balancing service. The only exception to this is for those customers who receive targeted sales service from the utility under SoCal's G-TARG tariff.

Second, the noncore transportation customers have not caused SoCal to retain the current level of firm capacity that it holds on El Paso's and Transwestern's combined systems. SoCal renegotiated its service agreements with El Paso and Transwestern during the last quarter of 1990. At that time, SoCal had the opportunity to elect to retain all or only a portion of the firm rights that it had previously held on those pipelines. SoCal elected to retain all of its existing rights on the two pipelines, subject to a limited option for relinquishment of capacity on El Paso's system at a future date. SoCal's retention of the current level of firm interstate capacity is not a result of its obligations to noncore customers, but a result of its obligations to core customers. Accordingly, to the extent that SoCal will use those capacity rights not needed by the core class to provide limited noncore services, the costs associated with those rights should be borne only by those customers who benefit directly from those services and only to the extent of the benefits received.

The witness for the Indicated Producers recommended that the Commission unbundle the charges for interstate transmission services from the rates for noncore intrastate transportation service, that noncore intrastate transportation customers be charged a rate that reflects only intrastate costs and that this change occur on October 1, 1991. This unbundling, it is argued, would be consistent with the Commission's cost-of-service rate policy and would prevent a distortion in the gas supply market. This distortion in the marketplace will create a real economic hardship to noncore customers and their suppliers who transport over Kern River, in the witness's opinion. Supplies shipped over Kern River's interstate system and SoCal's intrastate system will be unduly burdened with two sets of demand and reservation charges, namely the Kern River demand charge and the allocated interstate pipeline charges. In contrast, competing supplies shipped over existing pipelines will not bear double demand charges, but will reflect only the interstate pipeline charges allocated through SoCal's intrastate transportation rate.

3. Kern River

Kern River's argument is much the same as the Indicated Producers'. It argues that the fully allocated SoCal intrastate transportation rate includes costs for services or facilities that Kern River's customers are not using or for which they are already paying Kern River. Chief among the costs reflected in fully allocated rates are the demand/reservation charges associated with the existing interstate pipelines that serve SoCal. SoCal's fully allocated intrastate rate includes demand/reservation charges from El Paso, Transwestern, Pacific Interstate Transmission Company (PITCO), and Pacific Offshore Pipeline Company (POPCO). Since Kern River's customers will not be using any of the four interstate pipelines whose rates are reflected in SoCal's fully allocated intrastate rate, they should not be responsible for those costs.

Kern River points out that DRA recognizes that if Kern River shippers must pay SoCal's fully allocated rate, they will pay double demand charges for interstate pipeline capacity: once to Kern River and once as part of the fully allocated rate they pay to SoCal. Despite this recognition, DRA does not propose to make a change in cost allocation for such shippers in this proceeding. Kern River believes that this is basically inequitable and contravenes the competitive environment that the Commission has sought to develop.

Kern River contends that DRA's rate recommendation discriminates against Kern River shippers because whereas DRA recommends against unbundling rates in this proceeding for Kern River customers, it recommends a credit for customers that subscribe to relinquished El Paso capacity. DRA proposed that those who subscribe to El Paso capacity relinquished by SoCal and begin paying pipeline reservation charges directly to El Paso should be given a dollar-for-dollar credit against the intrastate rate charge by SoCal. But DRA proposed that shippers on new pipelines should continue to pay the fully allocated intrastate rate, even though they are not using existing interstate capacity and are paying reservation charges to the new pipeline. Kern River asserts that treating shippers on new interstate pipelines differently from those that subscribe to relinquished capacity on existing interstate pipelines places the shippers on the new pipeline at a significant competitive disadvantage; it is unfair and discriminatory.

4. Edison

SoCal intends to relinquish next year 300 MMcf/d of capacity on the El Paso system. Edison has executed an agreement with El Paso to acquire 200 MMcf/d of that capacity. As a result, Edison will start paying demand charges directly to El Paso in March 1992. In this proceeding, Edison asks us to resolve the following two separate issues: (1) how should SoCal's customers' rates reflect SoCal's relinquishment of capacity on the El Paso system and the concomitant reduction in demand charges that SoCal will pay; and (2) should the Commission unbundle interstate and intrastate transportation costs for those customers who subscribe directly to interstate capacity prior to implementation of capacity brokering?

Edison, as a firm shipper on the proposed Pacific Gas Transmission Company/PG&E expansion project, has a substantial interest in ensuring that the Commission addresses and resolves cost allocation and rate design issues in a manner that is fair to all customers - both core and noncore. However, Edison believes that the record in this proceeding is insufficiently developed to allow the Commission to decide the policy issues of unbundling at this time. Nevertheless it supports the proposal of others that the Commission establish a balancing account within which to record certain costs, until the Commission resolves these policy issues.

Edison observes that DRA proposes that customers acquiring relinquished El Paso capacity receive a credit for payments which they would otherwise make for the same capacity through SoCal's intrastate transportation rate. Edison and SoCal both support DRA's proposal. Other parties, including SCUPP and Indicated Producers, while having taken positions regarding the proper rate treatment for shippers on the new Kern River pipeline, have not opposed DRA's proposal. Only Kern River and TURN oppose DRA's proposal.

Edison argues that although parallels exist between the unbundling issue identified by the Kern River shippers and the issue of relinquished El Paso capacity, critical differences also exist which make it appropriate to separately consider these two issues.

To show the fairness of DRA's recommendation, Edison has put forth a hypothetical which assumes that SoCal currently has firm capacity rights of 100 units on the El Paso system for which SoCal incurs annual demand charges of $100. If SoCal allocates this $100 among the various customer classes on an equal cents-per-therm basis using cold year throughput, the results are as illustrated in Figure 1. As shown in Figure 1, Edison is allocated 10% of the total ($10), while all other customers are allocated the remaining 90% ($90).

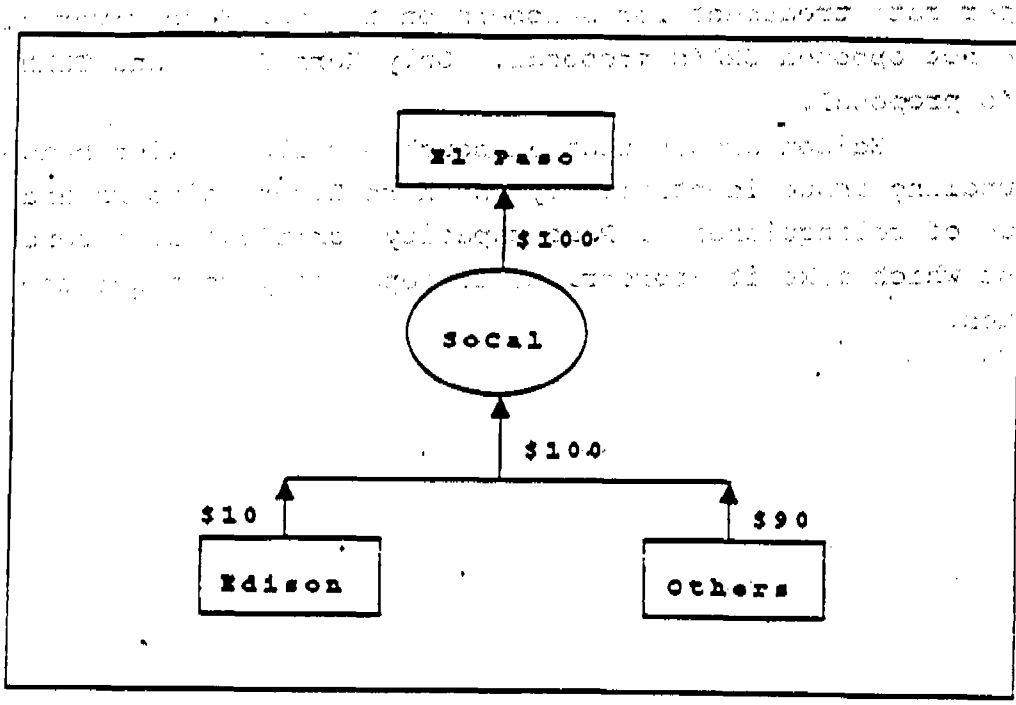

Figure 1

Assume further that SoCal relinquishes 10 units of firm capacity, resulting in a reduction from $100 to $90, in its annual demand charge obligation. The impact of this reduced SoCal demand charge obligation is shown in Figure 2.

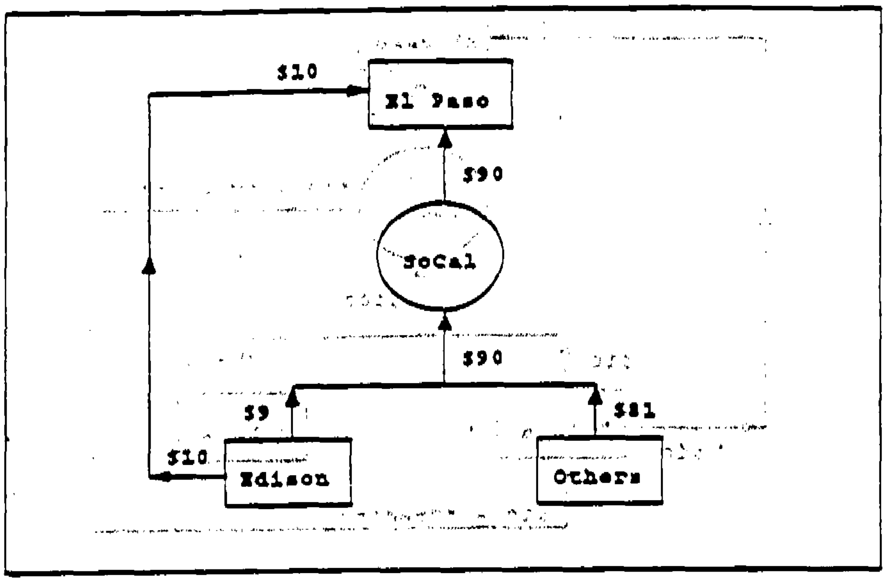

Figure 2

Since SoCal makes no adjustment to the equal cents-per-therm allocation factors, Edison's allocated share of the demand charges remains 10%, resulting in an allocation of $9. At the same time, Edison pays $10 directly to El Paso for the relinquished capacity, so Edison's total demand charge obligation has nearly doubled, from $10 to $19. Other customers, however, receive a $9 reduction in their allocation of demand charges.

Consequently, to answer the question about who would experience a cost reduction: the $9 reduction that would accrue to other customers would occur only because of the increase in Edison's total demand charge obligation, which will almost double in the example. To alleviate this situation, DRA proposes, and Edison urges, the crediting mechanism illustrated in Figure 3.

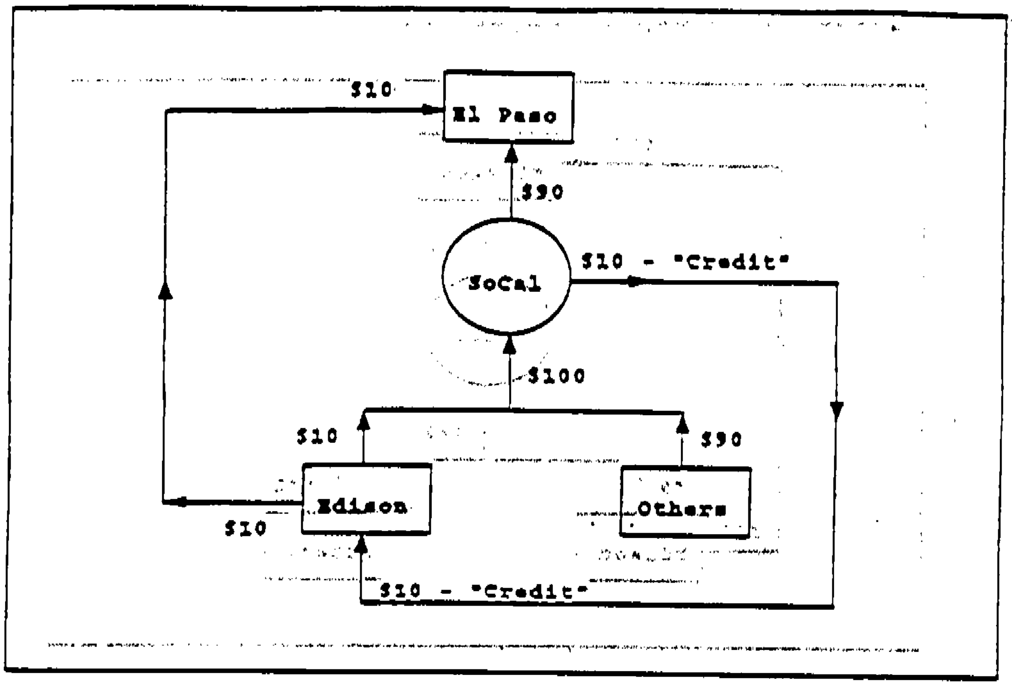

Figure 3

Under DRA's proposal, Edison's net demand charge allocation is $10, unchanged from the amount shown in Figure 1. Other customers, meanwhile, are allocated $90, which is also the same amount shown in Figure 1. Under DRA's proposal, thus, Edison avoids the payment of double demand charges while the allocation to all other customers remains unchanged from that which existed prior to relinquishment. The DRA's crediting proposal simply recognizes that Edison will assume direct payment of the El Paso demand charges that SoCal avoids as a result of capacity relinquishment.

5. Discussion

Although the description of the double demand charge issue, especially as it applies to Edison, has been lengthy, its resolution is brief.

We deny the request of all parties to make any changes in the method used to allocate interstate demand charges. Our first reaction to the plea that noncore shippers will pay double demand charge is that it is irrelevant. It is the shipper's choice to ship via Kern River or take firm service on El Paso. Having made the choice with full knowledge of the facts, and especially if they read our discussion of the issue in D.90-02-016, they should neither complain nor seek relief from their own actions. Our second reaction is that as a practical matter shippers will not actually pay a double demand charge because gas producers are expected to netback prices so that the California border price will be the same for all buyers. That was the finding in D.90-02-016 and there is no evidence in this proceeding to show any change in position by the producers. Our third reaction is that under DRA's proposal for Edison, Edison would be receiving 200 MMcf/d of firm rights to the California border at no cost. Our fourth reaction is that for SoCal to make this payment it would have to cook its books with our acquiescence. Under Edison's example, SoCal would only pay 90 units for El Paso service but would charge its customers as if it paid 100 units. This is a fictitious expense which generates a fictitious rate that should have no part in ratemaking. This fictitious rate will also generate franchise fees and uncollectible expenses to be paid by ratepayers.[5] If SoCal's costs are reduced SoCal's customers should benefit. Under DRA's and Edison's

5 All reports submitted by SoCal to Federal, State, and local agencies plus to private entities, which describe gross revenue, will reflect this fictitious cost and will, to that extent, be misleading. (At least without a footnote of explanation.)

proposal SoCal's costs are reduced but rates remain high and the difference is paid to Edison as a reward for leaving the system and getting firm service in place of interruptible. To reduce Edison's costs would trigger the same treatment for those who seek parity with Edison, e.g., the cogenerators.

Looking at Figure 2, which is the real world, when Edison leaves the system SoCal's cost go down and the "other" customers have their rates reduced by 10%. In the fictitious world, which is Figure 3, SoCal charges $100 for $90 of costs and the "others" pay an additional $9 so that SoCal can give that $9 to Edison. Edison pays an additional $1 which SoCal refunds to Edison. SoCal, of course, breaks even. Edison is 100% whole and has firm rights purchased with the "others'" money. And the ratepayer loses the firm rights and gets stuck with the bill. Welcome to the world of gas ratemaking.

The remaining issue is in regard to unbundling intrastate transportation rates from the interstate portion of the rate.[6] Putting aside the fact that there is no evidence of the amount of gas that will actually flow for the account of shippers who pay demand charges on interstate pipelines, the fact that with netback pricing there will be no real interstate demand charge, and that no party has presented a workable method of calculating and refunding this double demand charge, we reach the fact that the noncore parties, like Edison, have not shown why they should be

6 Edison's credit example is, with a minor modification, a paradigm for unbundling interstate and intrastate demand charges. If interstate demand charges are unbundled from SoCal's intrastate transportation rate then when Edison purchases 10 units of SoCal's El Paso rights SoCal's payments become $90 and the "others" continue to pay $90. Edison pays nothing toward SoCal's interstate demand charge because of the unbundling. Instead Edison's former $10 payment to SoCal for interruptible rights is transferred to El Paso for firm rights.

excused from payment. They claim they receive no benefits from SoCal's interstate rights. We find that they do. The interstate rights of SoCal provide security for the noncore, provide backup, and provide storage and storage gas; functions which would be significantly lessened or eliminated if SoCal did not have interstate rights of its own. The capacity brokering program, if implemented by unbundling of interstate demand charges, may ameliorate the noncore concern and at the same time protect the core customer from paying higher rates to compensate noncore customers. Lastly, if the noncore theory is taken to its logical extreme we would also have to exempt those core customers who receive gas service solely on the intrastate system from paying interstate demand charges. We are not prepared to exempt any customers from these charges.

In addition to the cogent discussion of ALJ Barnett in rejecting the requested relief from the "double demand charge", we wish to elaborate upon our concerns. First, the "double demand charge" term is misleading. SoCal has abandoned 300 MMcf/d of El Paso capacity effective March 1, 1992. SoCal's ratepayers will not be responsible for those charges as of that date. Edison's decision to acquire those firm rights does not relieve any existing ratepayer of any existing charges. In fact, Edison has acquired firm interstate capacity, an asset which they have not previously held. It is appropriate to pay more for a higher level of service. Whether or not Edison is paying too much for this level of service because of our own rate design is a question which cannot be answered based upon the record in this proceeding. We assure customers that acquire their own capacity, be it abandoned or new new capacity, that to the extent we are shown that intrastate rates shift an unreasonable burden onto those customers that we will act to the extent possible in the Capacity Brokering proceeding. It is the Capacity Brokering proceeding where such a showing properly belongs, and where we will properly visit this issue.

Second, serious concerns have been raised by Kern River and the Indicated Shippers concerning matters in which the Federal Energy Regulatory Commission (FERC) may have some jurisdiction. Without prejudging any of these issues, or our position upon these issues, we believe it is important to list some of our concerns and why it is prudent not to take action upon the "double demand charge" issue at this time since these issues were not fully litigated in this proceeding.

An issue of serious concern is whether or not a rebate to Edison, or to other customers who acquire abandoned capacity, runs afoul of non-discriminatory access. It is possible to view the status of El Paso abandoned capacity as equivalent to capacity of any other pipeline. It is capacity held by the interstate pipeline. Giving a rebate to customers acquiring capacity on El Paso and not to customers on Kern River may raise questions of discrimination. Whether such arguments would be sustainable through litigation is an open question. On the record before us in this case we can not make that determination.

We are also mindful of the argument that a shipper moving gas under abandoned El Paso capacity which it has acquired may argue that its end-use customers in California are entitled to the same credit which Edison claims it is entitled to. How to distinguish between these two end-users is not clear on the basis of the record before us. It may be both are entitled to such credits, or neither, or one and not the other. We simply can not make that determination at this time.

In terms of our process, we have an ongoing Capacity Brokering proceeding which will look into these matters in their entirety. That is the proper place to review these issues, and not in a BCAP.

G. Moreno Compressor Station -
<u>Moreno/Rainbow Corridor</u>

SDG&E owns and operates the Moreno compressor station which provides pressure for the Moreno/Rainbow pipelines, which are owned by SoCal. Most of the gas transported on these lines goes to SDG&E's customers although a small portion of the gas flows to SoCal's customers. DRA recommends that the costs of both the Moreno compressor station and the Moreno/Rainbow pipelines be allocated between SoCal and SDG&E on a volumetric use basis. SoCal supports allocating the costs of the Moreno/Rainbow pipelines on a volumetric use basis, but recommends allocating all of the costs of the compressor station to SDG&E as is currently done.

SDG&E argues that it operates the compressor station which in actual operation also provides compression for SoCal's customers. It is not a facility that is dedicated exclusively to the service of SDG&E customers.

SDG&E has proposed that it receive a credit in its cost allocation from SoCal in the amount of $465,000, representing the proportion of throughput due to service provided to SoCal retail customers downstream of the Moreno compressor station. SDG&E asserts that SoCal's customers along the Moreno to Rainbow pipeline route receive the benefits of SDG&E's Moreno compressor station.

SDG&E states that SoCal receives approximately 7% of the gas flowing from the Moreno compressor station and, as a result, should be allocated 7% of the cost of this facility. Currently SoCal and its customers along that route are not allocated any portion of the Moreno compressor station costs. SDG&E's customers are allocated the full amount. SDG&E has made a calculation to allocate to SoCal a portion of the Moreno compressor station costs using the same methodology SoCal uses to allocate its customer-related transmission facilities to SDG&E. If the same percentages are used the allocation of costs to SoCal is approximately $465,000.

SDG&E believes its throughput forecast for the Rainbow corridor is more accurate than SoCal's, and should be adopted. SDG&E claims SoCal's forecast was based on statewide numbers from the California Gas Report, while SDG&E's is based on pipeline-specific data. DRA agrees with SDG&E's forecast and allocation for these facilities. This throughput is used to estimate the $465,000 credit due SDG&E for the Moreno compressor station. SDG&E has proposed that the pipeline facilities that are not exclusively dedicated to SDG&E be placed in SoCal's demand related transmission category for allocation purposes. The specific SoCal facilities that SDG&E maintains should be transferred to SoCal's demand related transmission category are the two shared-use Moreno-Rainbow pipelines (1027, 1028) and the portion of the Coastline (1026) that is in Orange County. These transmission pipeline facilities serve both SoCal and SDG&E customers and should be treated no differently than the rest of SoCal's transmission facilities. The net result of implementing this proposal is to shift approximately $1.2 million of transmission costs to SoCal's other customers.

For the reason given by SDG&E, we will adopt its position.

H. Southland Chevron and El Paso Refunds

In D.90-01-015, SoCal was ordered to hold the Mid-Louisiana deferred tax and Southland/Chevron refunds to offset direct-billed Account 191 costs. That decision was reaffirmed in D.90-11-023, the 1990 SoCal ACAP decision. The El Paso general rate case settlement required that El Paso refund $6 million to SoCal. The Southland/Chevron refund was $75.7 million ($49.2 million received in June 1989 and $26.5 million received in December 1989). Transwestern was permitted to direct bill Account 191 costs $33.5 million to SoCal in July 1990. Since the El Paso settlement provides for crediting sales and transportation refunds against the Account 191 direct bill, there will be no Account 191 direct bill from El Paso. As a result, there is no longer any reason to hold the Southland/Chevron refund for offset against Account 191 billings and the excess of $42.2 million ($75.7 million less $33.5 million) plus the $6 million El Paso refund.

Both DRA and TURN have recommended that the estimated amounts of the El Paso and Southland/Chevron refunds, net of directly billed Account 191 costs, should be returned to ratepayers by offsetting SoCal's BCAP revenue requirement on the basis of equal cents per therm. For this purpose, DRA has accepted SoCal's estimated refunds net of interest and of Account 191 at $48.2 million. This approach is acceptable to SoCal.

Several parties have argued that this refund should be disposed of by way of a one time, lump-sum refund to customers. SoCal and TURN have presented evidence that it would be extremely difficult to ascertain which past customers are entitled to direct refunds because it is not clear who, if anyone, initially paid the amounts now being refunded. In addition, because this refund relates to a long historical period and this money was never directly reflected in rates in the normal sense, a one time, lump-sum refund would require enormous effort and administrative expense to determine which past customers are entitled to these refunds and could lead to potential litigation.

We agree with DRA and TURN. We have treated these same refunds, when made to PG&E, as an offset to rates on an equal cents-per-therm basis. No reason has been offered to persuade us that a different result is required for SoCal.

I. <u>Enhanced Oil Recovery (EOR) Revenue Allocation</u>

Because of the unique service characteristics of EOR customers we have treated all EOR revenues as strictly incremental, i.e., no costs shall be allocated to such loads. EOR revenues are to offset the revenue requirement borne by all other ratepayers. (D.87-05-046 at p. 20, and see the extended discussion pp. 18-22.) Currently, EOR revenue is credited to customer classes in proportion to the fixed margin allocated to each class, including interstate pipeline demand charges. Long Beach, and others, believe that this method is inappropriate and that EOR revenues should be credited to the various customer classes in proportion to their cold year throughput, in order to more accurately reflect the costs incurred by each class because of EOR service.

Long Beach argues that the current method is not appropriate because there is no causal relationship between EOR service and margin allocation by class. Under this method, the residential class is allocated the largest EOR credit because the residential class is the most margin-intensive class. Other classes are allocated relatively less EOR revenue because they are less margin-intensive. However, these results have little to do with the cost allocation burden imposed on the various customer classes due to the treatment of EOR on an incremental rather than an embedded cost basis. Long Beach believes it would be appropriate to allocate EOR revenue credits on a basis that is more in line with the cost responsibility that the various customer classes must assume due to the Commission's cost treatment of EOR service. Such an approach would better relate the benefits of EOR service (i.e., EOR revenue) to those customers who share in the costs that might otherwise be allocated to EOR service.

Long Beach's witness considered three alternate EOR revenue allocation approaches: cold year throughput, average year throughput, and functional cost responsibility, because EOR service is essentially a transmission service. He said if costs were allocated to EOR service in the same manner as costs are allocated to the various other customer classes, one would expect costs allocated to EOR service to be similar to those set out for the cogeneration and utility electric generation (UEG) classes. In other words, EOR service would bear a commensurate share of demand related transmission, demand related storage, pipeline demand charges, and 50% A&G factors. The appropriate share could be determined using any of the three approaches. In his opinion these approaches are superior to the existing EOR revenue credit methodology, because they more accurately credit EOR revenues in proportion to each customer class' cost allocation burden due to EOR service. Under his theory of cold year throughput allocation Long Beach's share of EOR revenue would increase from $641,000 to $1,945,000 while the core customer's share of EOR revenue would drop from $44,493,000 to $27,815,000.

TURN argues that Long Beach is doing nothing more than making a grab for more money for itself and others similarly situated. The current methodology allocates EOR revenue credits in a manner that gives each customer class an equal percentage reduction in its system fixed cost responsibility. Since these credits represent the EOR market's only contribution to system fixed cost, an equal percentage spread of the benefits is fair.

Long Beach's analysis, in TURN's opinion, proceeds from the false premise that the Commission's historic treatment of EOR customers represents a "cost allocation burden imposed on the various customer classes" and that there are "costs incurred by each class because of EOR service." TURN contends this is totally contrary to this Commission's long-standing rationale for its EOR policy. The Commission has always maintained that EOR revenues are incremental, because no volumes would move at full cost-of-service rates. Thus, it is incorrect to view the difference between full embedded cost and EOR contract rates as a revenue or cost recovery shortfall, or some kind of "burden" on other ratepayers. Incremental EOR revenues can be captured to the benefit of all ratepayers at market responsive rates, or those revenues can be lost entirely.

We agree with TURN. Our reading of D.87-05-046 shows that the Commission was fully aware of alternative methods of allocating core revenue and chose what it found to be reasonable. This was followed in D.87-12-039 over opposition similar to that offered by Long Beach. No facts have been presented which show our current method of allocation of EOR revenue is unfair. The arguments for change has been made before and were rejected; we reject them again.

VII. Rate Design

A. Residential Rate Design

1. Customer Charge

SoCal has proposed to raise the residential customer charge from $3.10 per month to $4.10 per month. The customer charge is at the level it was in 1986. SoCal's evidence shows that in real terms the customer charge has declined substantially and, at this point, would recover only about 25% of the fixed costs required to serve residential customers. In real terms the proposed $1 increase would merely return the customer charge to its 1986 level.

SoCal asserts that a customer charge which is far below actual cost results in cross-subsidies within the customer class, and becomes an inequity which is at odds with the Commission's general goal of achieving cost-based rates. An inadequate customer charge means that low volume users are subsidized by larger volume users which, in practice, means that customers in older, less energy-efficient homes subsidize gas service to generally more affluent residential customers in new energy-efficient homes.

DRA says that the average level of fixed costs incurred by each residential customer is at least $9. According to the DRA witness:

> "[R]ecovering at least a portion of these costs, as SoCalGas' tariffs do, in a customer charge is not only economically efficient but also equitable. If none of these fixed costs incurred by each customer are recovered in a fixed charge, then an undue burden is placed on the relatively large user, since customer costs would then be recovered volumetrically with each therm of usage."

DRA, however, objects to any effort to recover the full amount of the fixed costs through the customer charge because to do so would be inequitable since such costs are calculated on an average basis. Accordingly, DRA would fix the level of the customer charge at a level not to exceed the minimum level of fixed costs incurred by any given customer. DRA recommends a 50¢ increase to $3.60. TURN recommends no increase, on the ground that we have rejected this proposal on two previous occasions.

In D.90-11-023 we rejected SoCal's proposal to increase customer charges to $5 per month. We said "In D.90-01-015 we said the lower [customer] charge permitted greater customer control over gas use, maintained an appropriate balance of risk between ratepayers and utilities, and maintained conservation incentives. We will adhere to those reasons." (At p. 53.) The reasons set forth in D.90-11-023 remain convincing; we will continue the $3.10 charge.

2. <u>Tier Closure</u>

PU Code § 739.7 requires the Commission to reduce "high non-baseline residential rates as rapidly as possible." The Commission has interpreted this directive as requiring the closure between Tier I and Tier II residential rates to the extent possible while avoiding excessive rate increases to residential customers. The decrease in the average residential rate proposed in this proceeding presents an opportunity for significant closure between residential tiers while avoiding rate increases to virtually all residential customers.

The Tier I rate currently equals 56.9 cents per therm and the Tier II rate equals 80.1 cents per therm. The gap is 23.2 cents per therm. SoCal proposes to close this gap by 50% to 11.6 cents per therm. This proposal would produce an inclusive Tier I rate of 53.9 cents per therm and a Tier II rate of 65.5 cents per therm. This proposal would result in rate decreases to virtually all residential customers, except those with very low bills and monthly volumes well below 20 therms.

DRA recommends a 20% closure over the BCAP period to assure that all customers benefit from the overall rate decrease and to moderate the potentially severe bill impacts on low-use customers.

We will adopt SoCal's recommendation. Because of the rate decrease we are authorizing this is an ideal time to implement § 739.7 "as rapidly as possible."

B. <u>Edison/LADWP Service Agreements</u>

SoCal has recently executed a rate design agreement with Edison for UEG service and expects to execute a similar agreement with LADWP shortly. Key provisions in the Edison agreement are the following:

- o The agreement provides for a demand charge and a single volumetric rate.
- o The volumetric rate equals three (3) cents per therm.
- o The monthly demand charge is equal to the adopted season noncore UEG rate, minus the volumetric rate, times the adopted forecast of monthly deliveries.
- o In the event SoCal is unable to deliver the adopted throughput volume (as determined over an annual period based on average temperature conditions), the demand charge will be adjusted by a percentage equal to or less than a percentage of under-deliveries, depending on heating degree days experienced over the adjustment period.

Under the agreement all costs allocated to Edison are recovered through the demand charge and the volumetric rate and the demand charge provisions are such that the degree of possible revenue variation is less than that which would be present under all volumetric rates. Finally, the agreement does not frustrate the attainment of UEG/cogeneration rate parity because equality in rates between cogenerators and Edison is maintained on a forecasted basis as it has been under the UEG rate design in effect before August 1, 1991, the effective date of the new agreement with Edison. We conclude that rates for SoCal's sales to Edison should be based on the new rate design agreement.

C. Long Beach

Long Beach presently serves Edison power plants located in Long Beach and Huntington Beach. Long Beach has the physical capacity to serve Edison about 85,000 Mcf/d. Edison can receive this gas at either its Alamitos Generating Station Units 1 through 4, or its four units at Huntington Beach. SoCal serves Edison and LADWP UEG requirements in Long Beach under franchise agreements with Long Beach that will expire during the BCAP forecast period. Negotiations between Long Beach and SoCal regarding renewal of SoCal's franchises are continuing. Depending on the outcome of such negotiations, Long Beach's UEG demands may be increased substantially. Long Beach forecasts UEG demand of 60 MMcf/d, or about 21.9 Bcf on an annual basis. On a heating value basis, this is equal to 228,855 M therms, or about 27% higher than SoCal's forecast.

Long Beach disputes SoCal's forecast of Long Beach UEG demand because the forecast is based on historical data regarding Long Beach's monthly deliveries to Edison during noncurtailment months. Long Beach objects to the use of such historical data for this purpose and argues that the historical period reflects the effect of the rate design applied by SoCal to deliveries to Long Beach since May 1, 1988. That rate design has materially impaired the ability of Long Beach to serve Edison's requirements in excess of the forecasted requirements as it causes Long Beach's demand to be understated. The historical data also does not account for the effect of recent improvements in Long Beach's distribution system. Under current rate design the volumetric rate that SoCal has charged to Long Beach has exceeded the second tier volumetric rate that SoCal has charged to Edison. Under this rate design, Long Beach would serve Edison requirements in excess of forecasted volumes at an out-of-pocket loss to Long Beach. Thus, Long Beach may have "demand" for gas that it cannot serve, except at a loss. The historical period data incorporates this effect.

Long Beach asserts that the effect on it of a rate design where the Long Beach tail block wholesale rate and the SoCal tail block retail UEG rate are the same is to eliminate competition for incremental UEG loads, because Long Beach has no opportunity to economically serve incremental UEG loads when the costs it incurs to serve the incremental UEG load are added to the volumetric wholesale rate. Thus, equalizing wholesale and retail UEG tail block rates provides a competitive advantage to SoCal for serving incremental UEG loads.

To rectify this perceived inability to serve Edison loads, Long Beach proposes wholesale rates for Long Beach that are, on average, less than UEG retail rates. Its proposal would result in a wholesale tail block rate for Long Beach that is less than the retail UEG tail block rate. Long Beach justifies its reduced rate proposal on the ground that SoCal's rate proposals are not cost-based. They merely set portions of Long Beach's wholesale rate equal to tail block retail UEG rates, without any consideration of differences in allocated costs of service to UEG and wholesale customers. For example, in the 100% volumetric UEG rate design scenario, the wholesale price of gas destined for Long Beach's UEG load would be set equal to the retail UEG rate. This approach implicitly assumes that Long Beach has no costs of its own to serve its UEG loads. Long Beach, though, is confronted with customer-related and other costs to serve UEG loads. Long Beach believes it would be unfair for it to pay a 100% volumetric rate for UEG-related gas that also included costs independently incurred by Long Beach. Long Beach would, in effect, be paying these costs twice.

Long Beach submits that to be consistent with the Commission's policy commitment to cost-based rates generally, UEG and wholesale gas rates should reflect allocated cost. This concept affects the relative overall rate level. Wholesale and UEG rates should also be consistent as to average cost and incremental cost allocations. This concept affects the form of the rate design.

Long Beach recommends that the Commission implement a wholesale rate design that is fully consistent with UEG rate design. Considering the likelihood of a negotiated SoCal-Edison UEG agreement, the Commission should specify a mechanism for timely adjustment of wholesale rates to coincide with the effective date of rates under such a negotiated agreement. In the alternative, SoCal should be required to submit any negotiated UEG agreement for Commission approval. The Commission could then appropriately consider and adjust the SoCal-Long Beach wholesale rate design to reflect Long Beach's allocated cost of service, and as appropriate, the negotiated SoCal-SDG&E contract rate design.

SoCal points out that the default wholesale volumetric rate for Long Beach has been set for the last three cost allocation proceedings equal to the average retail UEG volumetric rates, that is, the average of the retail UEG Tier 1 and Tier 2 rates (D.87-12-039, pp. 104-105). This was recently reaffirmed by the Commission in D.91-05-039 where the Commission, among other things, eliminated demand charges for service to noncore customers. Under currently authorized cost allocation policies, wholesale customers are relieved of responsibility for the volumetric component of SoCal's A&G expense. As a result Long Beach's wholesale rate is below the average retail UEG rate. In light of the recent requirement for pure volumetric rates for retail UEG service imposed by D.91-05-039, a pure volumetric rate for Long Beach would render SoCal unable to compete for retail UEG load in Long Beach's territory. As SoCal's witness explained, such a result would create an annual windfall for Long Beach of $8 million at the expense of SoCal's other ratepayers.

To prevent this shift of cost responsibility from Long Beach to SoCal's other customers, SoCal has proposed a two-part rate design by which Long Beach would be charged the retail UEG rate for those particular volumes that Long Beach redelivers to UEG customers. The rate on Long Beach's non-UEG volumes is then reduced so that the average combined rate equals the average allocated cost for Long Beach. In this manner, SoCal has an equal opportunity to compete for sales to UEG load located in Long Beach, and there is no automatic shift of cost responsibility from Long Beach to other customers served by SoCal.

SoCal notes that the recently executed gas service agreement with Edison provides for a variable demand charge and a volumetric rate amounting to 3.0 cents per therm. To offer Long Beach a negotiated rate featuring a volumetric charge of less than the 3.0 cents per therm marginal rate applicable to SoCal's service to Edison would only ensure that SoCal would have no opportunity to serve incremental demand at Edison's UEG units located in Long Beach. The consequence of this, of course, would mean a significant shift in cost responsibility from ratepayers in Long Beach to SoCal's retail customers.

DRA supports a rate design for Long Beach that provides parity at the margin with the rate paid by Edison. Edison and SoCal have negotiated a customer-specific contract that charges $0.03/th at the margin. Long Beach should be charged this rate with a demand charge to recover the balance of allocated cost.

We agree with DRA. Long Beach's request for rates lower than those SoCal charges Edison is difficult to understand. Edison receives approximately 120 MMDth per year over SoCal's distribution system while Long Beach receives approximately 30 MMDth per year. Yet Long Beach declares itself a wholesale customer entitled to a lower rate than charged to Edison. (Whether under this circumstance Long Beach can be considered a wholesale customer in contrast to Edison's classification as a retail customer is a question for another day.) Why customer A who takes 75% less service than customer B is entitled to a lower rate than customer B has not been explained. Certainly Long Beach's witness, when asked the question, could not explain it. Long Beach's request for a lower rate than Edison is, to use a current phrase, counterintuitive, and not supported by the record.

Long Beach's assertion that it should pay a lower rate because it has its own costs makes no economic sense. It is SoCal's costs that matter. We are concerned with relationships between SoCal and its customers, with equity between classes, not with whether one customer's costs are higher or lower than another's.

D. Igniter Fuel and Cogenerator Parity

The California Cogeneration Council (CCC) asserts that SoCal's rate for cogeneration service violates statute and Commission policy. It argues that SoCal has proposed a default rate for transportation service to noncore cogeneration customers of 9.713 cents per therm. However, the equivalent default rate for noncore UEG transportation service equals 9.363 cents per therm, approximately 4% lower than the rate for the cogenerators. The discrepancy results from the inclusion of transportation costs associated with UEG igniter fuel service, a core service, in the costs used to calculate the default rate for noncore service to cogenerators. As discussed below, we will reclassify igniter fuel as Priority P-2B and combine the igniter fuel volumes with other UEG load; therefore, the controversy of whether to include igniter fuel volumes as part of the cogenerator parity rate calculation is now moot.

Igniter fuel transportation for UEGs should be included in Service Level 2 and accorded Priority P-2B status. Igniter fuel volumes should be included in the UEG class (noncore) for purposes of cost allocation. The rate to be charged by SoCal for igniter fuel transportation should be the noncore UEG default rate plus the 12 cents per decatherm Service Level 2 surcharge.

E. Monthly vs. Annual Distribution of Service Level Credits

The Commission has recently afforded gas utilities an option of distributing Service Level 2 surcharge revenues either on a monthly basis or at the end of a ratemaking period, subject to "true-up" in either event (Resolution G-2948, Conclusion 77, p. 72). As a result of this choice, SoCal has elected to distribute the interruptible service discount to the eligible noncore customers on a monthly basis in order to minimize variances which could become substantial if the credits are reconciled on an infrequent basis. DRA supports SoCal because a month-to-month true-up gets the credit to the interruptible customers as fast as possible and avoids the problem of a mismatch of customers receiving service and receiving credits.

We agree with SoCal and DRA.

F. Lost and Unaccounted for Gas (LUAF)

LUAF costs are presently allocated to all customers at both distribution and transmission levels based on average-year throughput. SoCal, DRA, and TURN support the present allocation, but Edison, SDG&E, and others believe that the time has come to change the allocation in order to more properly reflect cost responsibility. Edison and SDG&E placed in evidence a 1988 SoCal study of LUAF costs which purports to show that LUAF costs are the result of the distribution system and not the transmission system.

Based on its identification and investigation of four components of LUAF, the study concluded that LUAF costs should be allocated based upon distribution level throughput. According to the study, the first component, leakage, is entirely the responsibility of the distribution system since any gas lost on the transmission and storage systems is accounted for. The second component, measurement error, is attributable to small meter set assemblies (MSA), all of which are on the distribution system. The third component, gas theft, occurs only at the distribution level. The fourth component, losses from measurement variations due to temperature, is also attributable to smaller MSAs, since the larger MSAs have temperature correcting devices attached. Under SoCal's Case A, LUAF costs allocated to Edison are estimated at a two-year average of $3.267 million. Under the allocation methodology proposed by SoCal's study, no LUAF costs would be allocated to Edison because, by not utilizing the SoCal distribution system, Edison does not cause SoCal to incur LUAF costs.

TURN, supported by DRA, argues that the SoCal study should not be the basis of a reallocation of LUAF costs. The study was not sponsored by SoCal, no SoCal witness testified in support of it, it has already been refused by the Commission in D.90-01-015, and a new study of LUAF costs is in preparation by SoCal, expected in 1992. Further, a PG&E LUAF study contradicts many of the conclusions presented in the SoCal study.

In D.90-01-015 we considered the SoCal study but decided that there was insufficient time to determine its validity. We said:

> "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 customers classes."

Although the applicability of PU Code § 739.6 is no longer an issue, we have still not determined the validity of the SoCal study and SoCal did not sponsor it in this proceeding. Without a witness we cannot determine validity. Unlike fine wine, a study does not improve with age.

G. <u>The City of Vernon</u>

The City of Vernon is wholly located within SoCal's service territory and is crossed by major existing and proposed transmission pipelines of SoCal. Vernon established a municipal gas utility department on June 20, 1991, more than two years after receiving a request to consider doing so from a group of 19 major industrial gas users located in Vernon who sought improved service and lower rates. During that two-year period, Vernon attempted to negotiate with SoCal to meet the needs expressed by the customers, and failed. Approximately three weeks before the commencement of hearings, Vernon notified SoCal by letter dated June 20, 1991, of its desire to become a wholesale customer. The letter stated that on that very date a resolution had been adopted by Vernon authorities creating the City of Vernon gas municipal utility department. The letter said that Vernon intended to build a parallel distribution system whereby the newly formed Vernon gas department would compete with SoCal for the right to provide service to the 19 or so largest industrial customers in Vernon and formally requested SoCal to propose a tariff containing "terms, conditions and proposed rates for wholesale natural gas transportation service by SoCalGas to Vernon." SoCal declined.

Vernon offered testimony which proposed a wholesale tariff for Vernon. In developing its initial interim wholesale rate, Vernon proposed to follow the same basic cost allocation principles used to develop rates for SDG&E and Long Beach. Vernon was concerned, however, that applying those principles would not result in a truly cost-based rate, one which reflects only the services Vernon actually uses or the benefits it receives. It believes a thorough review of the Commission's overall cost allocation policy and a detailed cost of service study are necessary in order to set a more appropriate, and probably lower, rate. However, given that SoCal has already filed its BCAP application without proposing a rate for wholesale service to Vernon, and given the limited amount of time during this hearing, Vernon is willing to use the same basic cost allocation principles applied to SDG&E and Long Beach as a reasonable starting point for the purpose of determining the initial interim rates it should pay to SoCal. Vernon expects initially to serve a group of roughly 20 large industrial customers with constant, high load factor loads. Most of the 20 are process gas users; two or three are cogenerators. Vernon may also serve gas to its electric generation peaking unit. Vernon does not expect to serve any residential or small commercial load; rather, those customers will continue to be served by SoCal's distribution system unless and until Vernon installs sufficient gas distribution facilities to serve those customers, too.

SoCal moved to exclude the issue of wholesale gas service to Vernon on the grounds that Vernon's plans, however well-intentioned, are insufficiently developed for them to be included in the BCAP demand forecast, and it is not clear that Vernon is entitled to wholesale service. SoCal argues, first, the engineering study commissioned by Vernon concerning the design and configuration of the system the gas department envisions for construction will not even be completed for 60 to 90 days. Construction time, of course, is unknown. Second, it is far from clear which customers Vernon intends to serve. Its proposed testimony suggests that Vernon currently intends to compete with

SoCal for the right to serve only the 19 or so largest industrial customers within the city, leaving the balance for SoCal.

SoCal contends that the configuration of Vernon's proposed distribution system, the estimated completion date, and the customers Vernon would serve are all critical variables which would not only influence the impact of Vernon's plans on SoCal's BCAP demand forecast and rate design proposals, but also, pending resolution of these unknowns, would foreclose any prospect that a wholesale tariff could be designed and submitted to the Commission for approval within the time constraints of this BCAP. The lack of specificity as to which customers Vernon proposes to serve, as well as the design and configuration of the Vernon gas department distribution system, including the necessary interconnection with SoCal's transmission facilities, make it unlikely that the real impact of Vernon's proposal can be known any time soon.

SoCal asserted that Vernon's proposal is completely dissimilar from the relationships SoCal has with its other wholesale customers. Any interim rate design based on cost allocation principles applicable to Long Beach and SDG&E, therefore, would be a futile exercise. Indeed, testimony in the record indicates that Vernon's interim rate design proposal would shift about $7.5 million of costs presently paid by retail customers in Vernon to SoCal's remaining retail customers. Any interim rate which has this result as a proxy for legitimate cost-based rates simply underscores, in SoCal's opinion, the undeveloped nature of the proposal.

SoCal raised the legal question of whether Vernon is entitled to wholesale service at all. It explains that Vernon's proposal for wholesale service is dramatically different from the existing wholesale tariffs by which SoCal renders service to Long Beach and SDG&E. While Long Beach and SDG&E offer service to every customer within their respective geographic service territories, Vernon proposes to serve only selected customers in competition with a public utility which already serves the service territory pursuant to a franchise agreement granted by Vernon. SoCal maintains that it is far from clear whether it can be required to serve an applicant for wholesale service when the applicant has no service territory of its own and only intends to compete for the most lucrative customers with the very entity to whom it granted the franchise rights in the first place.

SoCal argued that it would considerably expand the hearings to obtain the information required to set a reasonable rate for Vernon because (1) the feasibility study relating to Vernon's proposed distribution system is still months from completion, (2) construction of Vernon's proposed distribution system cannot even begin until the study is complete, (3) the customers Vernon intends to serve have not yet been identified, (4) the wholesale gas demand of Vernon's gas department is unknown, (5) the interconnection facilities necessary to serve Vernon have not been identified, designed, or constructed, and (6) the costs allocable to Vernon, because of the uncertainties of their proposal, have not been developed.

The ALJ granted SoCal's motion and excluded the issue of wholesale gas service to Vernon on the ground that to include the issue would unduly expand the hearing in contravention of Rule 54. Vernon purported to "appeal" from the ALJ's decision. That purported appeal will be dismissed as there is no appeal from a procedural or evidentiary ruling of a presiding officer. (Re McCaw Communications D.90-02-048 in A.89-04-058.) However in this decision we will review the ruling.

The ruling of the presiding officer was correct. The SoCal BCAP is a procedure which is governed by a tight schedule (Re Rate Case Plan D.89-01-040 in R.87-11-012, App. D) to ensure a prompt decision. To have heard Vernon's request would have required an extended period to gather the necessary facts and to permit discovery, if needed, by all parties. The issue of authorizing wholesale rates to a city so that it may undercut SoCal's service is not one that can be decided without a thorough hearing and a complete record. The implications involved in the shift of costs to the remainder of SoCal's system are enormous. Wholesale rates authorized for Vernon would set a precedent for the entire state. This is not a minor issue to be resolved among the myriad of issues in a BCAP, but a serious attempt to realign gas service throughout California. The issue deserves a separate hearing as the ALJ recommended. Vernon's offer to accept the same wholesale rate as authorized for Long Beach assumes that Vernon is entitled to a wholesale rate. We are not prepared to make that assumption.

H. UEG Customer-Related Transmission Costs

At the hearing, TURN established that approximately $1.0 million in customer-related transmission costs associated with facilities dedicated exclusively to UEG customers have up until now erroneously been lumped in with the general pot of customer-related costs and thereby allocated almost entirely to the core. TURN requests that we reallocate these costs to the UEG class, thereby mirroring the treatment already given to customer costs associated with SDG&E-dedicated facilities. We shall adopt TURN's position.

In their brief SCUPP/IID argued in favor of direct assignment of these costs in the form of facilities charges to the appropriate customers within the UEG class (Edison and LADWP). SoCal opposes this request, stressing the lack of any record on this point. The record did not explicitly address the intraclass allocation of these costs. However, since they are facilities charges which are clearly disaggregated in SoCal's workpapers, logic dictates they be directly assigned within as well as to the UEG class. SCUPP/IID's proposal is a reasonable request for clarification and is adopted.

VIII. San Diego Gas & Electric Company Issues

Most of the issues raised by SDG&E have been discussed and resolved in the SoCal portion of this decision. In this section we discuss those remaining issues which are pertinent only to SDG&E and its customers and which have not been agreed upon by the parties.

A. Forecasts of Spot Gas and SDG&E's Core Weighted Average Cost of Gas

SDG&E forecasts that its WACOG will average $2.25/Dth at the California border during the forecast period. SDG&E estimates that all of its purchases will be made entirely from the spot market. DRA's forecast is $1.94/Dth (Yr. 1) and $1.93/Dth (Yr. 2). This difference is primarily due to the assumption made by DRA that reduced interstate pipeline transportation charges will be passed on to California consumers on a dollar-for-dollar basis. SDG&E believes that this is an unreasonable assumption on which to base rates. We agree with SDG&E. SDG&E's estimate is reasonable and should be adopted.

B. Rate Design

1. Core Rates

a. Residential Tier Closure

SDG&E proposes to change the allocation between baseline and nonbaseline rates depending on whether the overall change to the residential class is an increase or decrease. If the overall residential group average rate change is positive, an increase to both baseline and nonbaseline rates would be applied based on equal cents per therm. If the overall residential group average rate change is negative, the entire decrease would be applied to the nonbaseline rate. This approach continues to decrease the differential ratio with the consideration of a minimum impact on the residential customer bills.

DRA recommends closing the absolute tier differential between Tier 1 and Tier 2 rates by 10%. Senate Bill (SB) 987 directed that the tier differential be closed as quickly as possible, but not at the expense of causing rate shock. DRA's proposal accomplishes both of these goals. Absolute tier closure of 10% is equitable to both low usage and high usage customers, and consistent with past tier closure decreases. Further, reducing the absolute tier differential will close the gap between Tier 1 and Tier 2 much more quickly than SDG&E's proposal to merely reduce the tier ratio. DRA's recommendation is reasonable and should be adopted.

2. Borrego Springs LNG Service

The Roadrunner Club is a 326-space mobilehome park located in Borrego Springs, California. The Roadrunner Club Association, Inc. (Association) is the association of mobilehome owners (customers) within the Roadrunner Club. Wright & Company (Wright) is the owner of the Roadrunner Club. Collectively the Association and Wright will be referred to as "Roadrunners."

The interest of Roadrunners is limited to liquid natural gas (LNG) service provided by SDG&E to the Roadrunner Club. Three hundred twenty-one of the 326 spaces are plumbed for gas and wired for electric service. The remaining five are wired for electric service, but not plumbed for gas service. LNG service is also provided to Roadrunner Club common area facilities. SDG&E serves the LNG customers within the Roadrunner Club on rate Schedule GL-1.

Roadrunner Club residents are the only SDG&E customers served under GL-1 and they are the only remaining SDG&E LNG customers remaining from a pilot test program initiated in May of 1968 (D.74169). The purpose of the test program was to provide an opportunity for the development of the then emerging concept of using LNG to, among other things, fuel vehicle fleets, and to provide Commission-regulated natural gas service to remotely situated communities. The Commission's decision envisioned eventual widespread use of LNG, and in some cases as a competitive alternative to unregulated liquified petroleum gas (LPG) suppliers. The Roadrunner Club is a case in point. It was recruited at the beginning of the LNG program by SDG&E competing against LPG suppliers. The LNG venture failed and SDG&E only attempted to serve LNG to a total of 31 large customers and communities, including the Roadrunner Club. Today, SDG&E has terminated LNG service to 30 out of the 31 customers, leaving only the Roadrunner Club.

The current Schedule GL-1 rates were established in SDG&E's last ACAP by D.90-11-023 (A.90-03-049). In that proceeding, SDG&E sought a 116% increase in GL-1 rates, phased in over an 18-month period. SDG&E claimed that it was trying to implement "cost-based rates" and eliminate what it calculated as a $149,053 annual subsidy to LNG customers (based on the annual cost of service versus revenue at then current rates). The deficit was primarily due to the cost of LNG exceeding the cost of natural gas. DRA generally supported SDG&E's proposal but recommended a more moderate increase to the facility charge and proposed a new commodity surcharge with a phased-in increase over a three-year period. Roadrunners opposed the increase. We granted a modest increase, which brought the Roadrunners' average combined LNG and electric bill up to the average all-electric bill in the Borrego Springs area.

In this BCAP SDG&E proposes a 10.5% rate increase for LNG service to the Borrego Springs area. SDG&E states that this increase over present average rates is designed to move toward the cost of providing this service. DRA supports SDG&E. Roadrunners oppose.

The issue raised by SDG&E in its proposal to increase its LNG rates to Borrego Springs was extensively litigated in SDG&E's last ACAP D.90-11-023 where we denied SDG&E's rate proposal but increased rates to meet the average Borrego Springs all-electric user's bill. We said that we would "...not approve rates that would increase the Roadrunners' average combined LNG and electric bill to exceed the average Borrego Springs all-electric user's bill." (At p. 63.)

Our view of the cost responsibility of the Roadrunners has not changed since D.90-11-023. We expect the Roadrunners to pay, on average, no more than the all-electric customers in Borrego Springs pay, on average, for service. We do not expect the Roadrunners to bear the entire burden of a failed experiment. Over the years LNG expenses will increase, but the Roadrunners will stay static or decrease. It is inequitable to impose this burden on so few. (D.90-11-023 at p. 63.)

SDG&E has presented evidence that under proposed rates an average monthly combined gas and electric bill for the Roadrunners when compared to the average rate for all-electric users in Borrego Springs is Roadrunners \$79.30 - all-electric \$83.29. The Roadrunners' bill is comprised of \$38.51 electric plus \$40.79 LNG. Under the circumstances SDG&E's proposed rate increase is reasonable.

<u>Findings of Fact for SoCal</u>

1. DRA's Refiners Acquisition Cost of Crude (RACC) forecast of \$19 per barrel for BCAP year one and BCAP year two should be adopted.

2. DRA's spot gas forecast of \$2.01/MMBtu for BCAP year one and \$1.96/MMBtu for BCAP year two should be adopted.

3. DRA's forecast for the single portfolio SoCal WACOG of \$2.11/Dth for BCAP year one and \$2.01/Dth for BCAP year two should be adopted.

4. DRA's core demand forecasts should be adopted.

5. DRA's retail UEG demand forecasts, after adjustment for the LADWP in order to reflect a two-tier rate, should be adopted.

6. The noncore industrial manufacturing employment forecast of SoCal should be adopted.

7. Demand forecasts for the nonresidential core and nonresidential noncore customer classes, insofar as they are influenced by customer service level elections made in the SoCal "open season," number of "economic practicality" applications received by SoCal before August 1, 1991 which have been submitted to the Commission for approval, core subscription volumes selected in the SoCal "open season," and core aggregation transportation applications which have been completed by August 1, 1991, should be based upon updated filings made by SoCal in this proceeding to reflect such customer selections.

8. The SoCal-Long Beach UEG demand forecast of 46 MMcf/d is properly based upon historical data and should be adopted.

9. The non-EOR cogeneration demand forecast of SoCal, after adjustment for updated heat rates pursuant to Commission Resolution G-2946, is reasonable and should be adopted.

10. DRA's forecasts of arithmetic weighted average spot prices are reasonable and should be adopted.

11. The DRA single portfolio SoCal WACOG forecasts in this proceeding are reasonable and should be adopted.

12. The definition of MPO originally set forth in D.87-12-039 is reasonable and should continue to be used as a valid calculation of MPO transition costs.

13. The forecast of the completion date of the Kern/Mojave pipeline of July 1, 1992 is reasonable and should be adopted.

14. TURN's forecast of an additional 50 MMcf/d of additional throughput resulting from the Transwestern Expansion is reasonable and should be adopted.

15. Capacity assumptions of 3,104 MMcf/d for BCAP year one and 3,296 MMcf/d for BCAP year two are reasonable and should be adopted.

16. A forecast of fixed pipeline demand charges of $327.6 million for BCAP year one and $316.4 million for BCAP year two should be adopted. This forecast reflects the reduction of SoCal's

demand charges payable to El Paso upon SoCal's relinquishment of 300 MWcf/d of firm capacity on March 1, 1992.

17. SoCal has properly reflected curtailment by service level elections in its throughput and curtailment forecasts, both of which should be adopted.

18. LUAF costs should be based on a factor of 1.2% of total system throughput.

19. Forecasts of balancing and tracking account over/undercollections presented on behalf of SoCal, as updated by SoCal on September 27, 1991, are reasonable and should be adopted.

20. The most recent available recorded balance of the seasonal rate shortfall account, together with the forecasted shortfall for October and November 1991, should be adopted, with the difference between estimated and actual shortfalls being trued-up in the next BCAP cycle.

21. DRA's proposal that SoCal's total revenue requirement be reduced by an amount purportedly equivalent to the reduction in noncore procurement activity under D.90-09-089 should be rejected.

22. SoCal should not be at full risk for shortfalls in brokerage revenues and should have the opportunity to recover the $4.23 million previously authorized by the Commission for brokerage fees less any shortfall which occurs prior to the effective date of this decision.

23. SoCal's costs of interutility transportation fees paid to PG&E for transportation services, which have previously been found reasonable by the Commission and which are incurred from August 1, 1991 through the effective date of this BCAP, shall not be recovered.

24. Pitas Point revenue requirements (franchise fee and uncollectible expense) should be treated in the same manner as transmission costs and allocated on that basis.

25. All "stranded" Pitas Point franchise fee and uncollectible expense, which are no longer being recovered from

noncore procurement customers due to the elimination of the noncore portfolio as of August 1, 1991, should not be recovered.

26. Tracking accounts for Pitas Point franchise fee and uncollectible expense for the BCAP period should be adopted.

27. SoCal's request for recovery of undercollections in the Cogeneration Shortfall Account in the amount of $99,000 should not be adopted.

28. DRA's proposal to amortize balancing account net undercollections over 12 months is reasonable and should be adopted.

29. The pilot storage banking program has been extended for an additional year; therefore, the forecasted storage banking revenue credit of $4.5 million should be removed from the revenue requirement.

30. SoCal's recommendation to functionalize a greater percentage of A&G expense should not be adopted at this time.

31. SoCal's recommendation to update the methodology for allocating common distribution costs on the basis of the design peak hour load for core customers and the coincident hour load for noncore distribution customers should not be adopted.

32. TURN's proposal to allocate market services costs on the basis of throughput should be rejected.

33. The traditional classification of market services expenses as customer related, which are allocated on the same basis as distribution plant, should be maintained.

34. DRA's proposal to allocate costs on the basis of cold year demand rather than throughput should be rejected.

35. Rates should be implemented in this proceeding on the basis that all currently forecasted P2A volumes, with the exception of those that have already applied for noncore status through the economic practicality process, will remain in the core market cost allocation, with revenues from such customers who actually transfer during the BCAP period to noncore status being assigned to the Core

Fixed Cost Account. The transfer of volumes to noncore status for cost allocation and ratesetting purposes will be deferred to the next cost allocation proceeding. This approach is reasonable in light of the uncertainty involved in forecasting such transfers and should be adopted.

36. The various proposals for relief from the pipeline demand charge component embedded in SoCal's intrastate rates should be rejected.

37. Shippers who acquire firm capacity on the El Paso or Kern River pipelines knew or should have known that this Commission had refused to exempt them from SoCal's interstate demand payments to El Paso and Transwestern.

38. To authorize the credit for the demand charges noncore transportation customers pay directly for interstate service, as proposed by Edison and DRA, would be to create a fictitious expense to be paid for by the ratepayers.

39. To authorize the credit would require comparable treatment for cogenerators to maintain parity, with the loss of revenue being recovered from all other ratepayers.

40. Unbundling intrastate transportation rates from the interstate portion of the rate is not in the public interest at this time.

41. All classes of customers on SoCal's system benefit because all other classes use the system.

42. SoCal's interstate rights on El Paso and Transwestern benefit the noncore by making SoCal a strong company and by providing security for the noncore.

43. The EOR revenue allocation should be a credit to customer classes in proportion to the fixed margin allocated to each class, including interstate pipeline demand charges, as was done in SoCal's last ACAP.

44. To accede to Long Beach's request for a pure volumetric rate from SoCal would result in an annual windfall for Long Beach of $8 million at the expense of SoCal's other ratepayers.

45. Parity to cogenerators pursuant to PU Code § 454.4 results in an annual subsidy to cogenerators from SoCal's ratepayers of at least $9 million.

46. To permit the City of Vernon to present its case for wholesale rates in this BCAP would have unduly expanded the hearing in contravention of Rule 54.

47. The proposal of Edison and DRA that customers acquiring capacity relinquished by SoCal receive a dollar-for-dollar credit equal to the demand charge associated with the acquired capacity is not reasonable and should not be adopted.

48. SDG&E's proposal to allocate to SoCal a share of the costs associated with the Moreno compressor station and other transmission facilities in the Moreno to Rainbow Corridor should be adopted.

49. The DRA/TURN recommendation that estimated amounts of El Paso and Southland/Chevron refunds be returned to ratepayers by offsetting the BCAP revenue requirement is reasonable and should be adopted.

50. SoCal's recommendation for an increase in the existing residential customer charge from $3.10 to $4.10 per month should be denied.

51. SoCal's recommendation for an increase in the core commercial customer charges for Priority 1 and Priority 2 customers of $13 and $65 per month, respectively, should be adopted.

52. In accordance with PU Code § 739.7, "high non-baseline residential rates" should be reduced "as rapidly as possible" by closing the Tier 1 and Tier 2 differential by 50% as recommended by SoCal.

53. To prevent an unwarranted shift of cost responsibility from the City of Long Beach to SoCal's other customers, SoCal's

recommendation that the City of Long Beach pay a rate equivalent to SoCal's UEG retail service for its own UEG-related load should be adopted.

54. Rates for service to Edison should be based on the recently negotiated amendment to the SoCal/Edison Gas Service Agreement.

55. A UEG customer charge is not needed.

56. Igniter fuel transportation for UEGs should be included in Service Level 2 and accorded Priority P-2B status. Igniter fuel volumes should be included in the UEG class (noncore) for purposes of cost allocation. The rate to be charged by SoCal for igniter fuel transportation should be the noncore UEG default rate plus the 12 cents per decatherm Service Level 2 surcharge.

57. SoCal has identified approximately $1 million in annual costs attributable to UEG exclusive use transmission facilities that were excluded from the total plant costs used to derive the allocator for UEG customer-related costs. These customer-related costs should be excluded from the general system allocation and should be directly allocated to the UEG customer class and assigned directly to the UEG customers.

58. SoCal's election to distribute Service Level 2 surcharge revenues on a monthly basis subject to "true-up" should be approved.

59. The proposal of certain intervenors to allocate LUAF costs on a different basis should be deferred pending the results of the ongoing SoCal study of the issue.

60. TURN is found eligible for compensation pursuant to Rule 76.54. It has previously been found to have met its burden of showing financial hardship for 1991 in D.91-05-029; it has raised numerous issues in this proceeding; and it estimates its budget at $65,000.

61. The increases and decreases in rates and charges authorized by this decision are justified, and are just and reasonable.

Findings of Fact for SDG&E

62. SDG&E's gas price forecast is reasonable and should be adopted.

63. The throughput forecasts for SDG&E agreed upon by DRA and SDG&E should be adopted.

64. SDG&E should receive a carrying cost of storage inventory credit of $511,000 against its cost allocation from SoCal.

65. The DRA proposal to close the absolute tier differential between Tier 1 and Tier 2 rates by 10% is reasonable and should be adopted.

66. The average combined gas and electric bill for the Roadrunners at SDG&E's proposed LNG rate is $79.30 per month. The average all-electric customer bill in Borrego Springs is $83.29. A rate increase for the Roadrunners is justified.

67. A LIRA participation rate of 40% on the SDG&E system should be adopted for both BCAP years.

68. SDG&E's proposed core commercial and noncore retail rates should be adopted.

69. Winter adders for seasonally differentiated noncore volumetric rates should be calculated according to the methodology agreed upon by DRA and SDG&E.

70. SDG&E's UEG rate design proposal should be adopted.

71. SDG&E's core rate cap should be adopted.

72. SDG&E should be authorized to establish a noncore CCSI balancing account.

73. SDG&E's proposed allocation of storage banking credits should be adopted.

74. The increases and decreases in rates and charges authorized by this decision are justified, and are just and reasonable.

Conclusions of Law

1. Recovery of Pitas Point franchise fees and uncollectible expenses, recovery of undercollections in interutility transportation costs, and recovery of the shortfall in brokerage fees, all of which accrued between August 1, 1991 and the effective date of this decision, shall not be authorized because to permit recovery would constitute retroactive ratemaking.

2. An entity which purchases gas for resale is not by that fact alone entitled to a rate lower than other purchasers of equivalent amounts of gas.

3. The rate changes adopted for SoCal are set forth in Appendix H.

4. The rate changes adopted for SDG&E are set forth in Appendix K.

5. The adopted gas demand, deliveries, portfolio prices, costs, and supply forecasts for SoCal are set forth in Appendix D.

6. The adopted costs and single portfolio price forecasts for SoCal are set forth in Appendix E.

7. The adopted revenue requirement for SoCal is set forth in Appendix F.

8. The adopted cost allocation summary for SoCal is set forth in Appendix G.

9. The core bundled rates and revenues and the noncore transport rates and revenues adopted for SoCal are set forth in Appendix H.

10. The gas demand and supply forecasts adopted for SDG&E are set forth in Appendix I.

11. The gas costs and revenue requirements adopted for SDG&E are set forth in Appendix J, Tables 1a and 1b.

12. The core customer cost allocation, the noncore customer cost allocation, and the noncore transport rates and revenues adopted for SDG&E are set forth in Appendix J, Tables 2 and 3.

13. The core bundled rates and revenues and noncore rates and revenues adopted for SDG&E are set forth in Appendix K.

14. The ruling of the administrative law judge preventing the City of Vernon from presenting its case for wholesale rates is affirmed.

15. There is no appeal from the rulings of the administrative law judge. The "appeal" by the City of Vernon should be dismissed.

ORDER

IT IS ORDERED that:

1. Southern California Gas Company (SoCal) shall file, on or after the effective date of this order, and at least 3 days prior to their effective date, revised tariff schedules which implement the adopted changes shown in Appendix H.

2. SoCal shall file, 12 months after the effective date of the tariffs filed pursuant to Ordering Paragraph 1, new tariffs containing rate changes necessary to implement the balancing/tracking accounts amortization for the second BCAP year. In its filing, SoCal shall itemize the balancing/tracking account amortization. Rates for the second BCAP year shall be based upon the same average annual throughput data employed in establishing the rates adopted in this decision for the first BCAP year.

3. San Diego Gas & Electric Company (SDG&E) shall file, on or after the effective date of this order, and at least 3 days prior to their effective date, revised tariff schedules which implement the adopted rate changes shown in Appendix K.

4. SDG&E shall file, not later than 2 weeks after SoCal files new tariffs pursuant to Ordering Paragraph 2, new tariffs containing rate changes necessary to implement the balancing/tracking accounts amortization for the second BCAP year. In its filing, SDG&E shall itemize the balancing/tracking account amortization. Rates for the second BCAP year shall be based upon

the same average annual throughput data employed in establishing the rates adopted in this decision for the first BCAP year.

5. The revised tariff schedules shall become effective on or after January 1, 1992, and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

6. SoCal shall not recover Pitas Point franchise fees and uncollectible (FF&U) expenses accrued between August 1, 1991 and the effective date of this decision.

7. SoCal shall not recover undercollections in interutility transportation costs accrued between August 1, 1991 and the effective date of this decision.

8. SoCal shall not recover the shortfall in brokerage fees accrued between August 1, 1991 and the effective date of this decision.

9. Commencing with the effective date of this decision, SoCal may establish and maintain a balancing account for the purpose of recovering its currently authorized annual brokerage fee revenue requirement of $4.23 million. SoCal shall not record in this account any shortfall revenues for which recovery has been denied pursuant to Ordering Paragraph 8. The outstanding balance in this account shall be allocated equitably among the noncore in SoCal's next BCAP, in accordance with the methodology to be decided in that proceeding.

10. SoCal shall, in the second BCAP year, recover (or credit to ratepayers) the difference between actual and estimated Seasonal Rate Shortfall Account revenue for the months of October and November 1991 and allocate the revenue on an equal cents-per-therm basis to the retail noncore. Upon allocation of these "trued-up" revenues, the Seasonal Rate Shortfall Account shall be abolished.

11. The Division of Ratepayer Advocates' request in its June 24, 1991 letter to the Commission Advisory and Compliance Division that a tracking account be established to record the

difference between revenues associated with forecasted Priority 2A volumes for which requests for reclassification to noncore status were filed prior to the August 1, 1991 deadline specified in Resolution G-2948, and the revenues associated with the actual volumes so reclassified, is denied.

12. Subject to the proviso in Ordering Paragraph 14, SoCal shall book all revenues associated with Priority 2A volumes for which requests for reclassification to noncore status did not meet the August 1, 1991 deadline specified in Resolution G-2948, and which the Commission approves for such transfer, to the Core Fixed Cost Account (CFCA).

13. Toward Utility Rate Normalization's (TURN) proposal for subaccount tracking within the CFCA, of the difference between the actual revenues paid by Priority 2A customers transferring to noncore status after the August 1, 1991 deadline specified in Resolution G-2948, and the revenues which would have been received had these customers continued to be billed at core rates, is approved. Subject to the proviso in Ordering Paragraph 14, SoCal shall establish the subaccount as requested by TURN. SoCal's next BCAP will address the question whether and in what manner the outstanding balance in this subaccount will be allocated to customers.

14. Any Priority 2A customers applying for transfer to noncore status after the August 1, 1991 deadline specified in Resolution G-2948 shall be billed at core rates for all service rendered prior to the effective date of this decision.

15. The "appeal" by the City of Vernon from the ruling of the administrative law judge is dismissed.

16. SoCal may track the interest accrual on the $1.47 million transfer from the core PGA to noncore customers mandated in D.91-09-026, Ordering Paragraph 2.

This order is effective today.

Dated December 20, 1991, at San Francisco, California.

PATRICIA M. ECKERT
President
JOHN B. OHANIAN
DANIEL Wm. FESSLER
Commissioners

I will file a written dissent.

/s/ NORMAN D. SHUMWAY
Commissioner

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

NEAL J. SHULMAN, Executive Director

APPENDIX A

List of Appearances

Applicants: E. R. Island, David B. Follett, and Thomas R. Brill, Attorneys at Law, for Southern California Gas Company; and Keith W. Melville, Attorney at Law, and Beth A. Bowman, for San Diego Gas & Electric Company

Interested Parties: Barbara Barkovich, for Barkovich and Yap; Patrick J. Bittner, Attorney at Law, for California Energy Commission; Catherine M. Elder and John W. Jimison, Attorney at Law, for City of Vernon; Messrs. Jackson, Tufts, Cole & Black, by Evelyn Elsesser, Attorney at Law, for Messrs. Jackson, Tufts, Cole & Black; Michel Peter Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization; Messrs. Biddle & Hamilton, by Richard Hamilton, Attorney at Law, for Roadrunner Club Association, Inc., Wright and Company, and Western Mobile Home Association; Steve Harris, for Transwestern Pipeline Company; Messrs. Morrison & Foerster, by Lynn Haug and Jerry Bloom, Attorneys at Law, for Inland Container; David T. Helsby, for R. W. Beck & Associates; Michael Hopkins, for City of Glendale; Adrian J. Hudson, for California Gas Producers Association; Bruno Jeider, for City of Burbank; Messrs. Morrison & Foerster, by Joseph Karp, Attorney at Law, and MRW & Associates, Inc., by Dr. Robert B. Weisenmiller, for California Cogeneration Council; Keith R. McCrea and Michael T. Mishkin, Attorneys at Law, for California Industrial Group, California Manufacturers Association, and California League of Food Processors; Ronald G. Oechsler, for Recon Research Corporation; Melissa Metzler, for Bakarat & Chamberlin; Leamon W. Murphy, for Imperial Irrigation District; Messrs. Jones, Day, Reavis & Pogue, by Norman A. Pedersen, Attorney at Law, for Southern California Utility Power Pool; Robert L. Pettinato, for Los Angeles Department of Water & Power; Florence Pinigis, Attorney at Law, for Southern California Edison Company; Patrick J. Power, Attorney at Law, for City of Long Beach; Andrew Safir, for Canadian Petroleum Association; Andrew Skaff, Attorney at Law, for Kenetech Corporation and Broadstreet Oil & Gas; Messrs. Armour, Goodin, Schlotz & McBride, by James Squeri, Attorney at Law, for EOR Producers/Cogenerators; Alex Szabo, for City of Pasadena; Kevin Woodruff, for Henwood Energy Services, Inc.; Randolph L. Wu, Attorney at Law, and Phyllis Huckabee, for El Paso Natural Gas Company; Mark R. Huffman, Attorney at Law, for Pacific Gas and Electric Company; and Graham & James, by Melissa Waksman, Attorney at Law, for Kern River Transmission Company.

Division of Ratepayer Advocates: Hallie Yacknin, Patrick L. Gileau, Attorneys at Law, Fay Fua, and Robert Mark Pocta.

(END OF APPENDIX A)

SOUTHERN CALIFORNIA GAS COMPANY
Summary of Revenue Changes

Effective January 1, 1992

	Revenue at Present Rates ($000)	Revenue at Adopted Rates ($000)	Increase (Decrease) ($000)	Percent Change
CORE 1/				
Residential	1,813,849	1,664,765	(149,083)	-8.22%
Commercial	654,444	597,879	(56,565)	-8.64%
Transport only	24,607	29,796	5,188	21.08%
Core Total	2,492,900	2,292,440	(200,460)	-8.04%
NONCORE 1/				
Industrial	96,414	133,504	37,089	38.47%
UEG	113,508	159,672	46,164	40.67%
Cogeneration	39,131	53,981	14,850	37.95%
Cogen LTKs	990	862	(128)	-12.92%
Subtotal	250,043	348,019	97,976	39.18%
WHOLESALE				
Long Beach	20,234	19,355	(878)	-4.34%
San Diego	83,439	79,881	(3,558)	-4.26%
Wholesale Total	103,673	99,236	(4,437)	-4.28%
Noncore Total	353,716	447,255	93,539	26.44%
System Total	2,846,617	2,739,695	(106,921)	-3.76%

1/ Core bundled revenue and noncore transportation revenue

NOTE: Due to adopted 12-month balancing account amortization, revenue changes apply only to the first BCAP period.

END APPENDIX B

SAN DIEGO GAS & ELECTRIC COMPANY
SUMMARY OF REVENUE CHANGES

Effective January 1, 1992

CUSTOMER GROUP	ADOPTED SALES	PRESENT REVENUE	PRESENT AVG RATE	ADOPTED REVENUE	ADOPTED AVG RATE	REVENUE CHANGE	RATE CHANGE	PERCENT CHANGE
	mtherms	m$	C/therm	m$	C/therm	m$	C/therm	%
CORE								
Residential	330,442	183,989	55.680	193,309	58.500	9,320	2.820	5.1%
Commercial	112,932	64,678	57.272	67,622	59.879	2,944	2.607	4.6%
TOTAL CORE	443,374	248,668	56.085	260,931	58.851	12,264	2.766	4.9%
NON-CORE								
Industrial	67,608	21,302	31.509	21,591	31.936	289	0.427	1.4%
Cogeneration	160,450	42,396	26.423	42,861	26.713	465	0.290	1.1%
UEG	427,116	137,905	32.288	140,506	32.897	2,601	0.609	1.9%
TOTAL NON-CORE	655,174	201,603	30.771	204,959	31.283	3,355	0.512	1.7%
RATE REVENUES	1,098,547	450,271	40.988	465,890	42.410	15,619	1.422	3.5%
MISC. REVENUES		3,152		3,152		0		0.0%
TOTAL REVENUES		453,423		469,042		15,619		3.4%

Rates reflect 1992 attrition allowance.

TABLE 1

SOUTHERN CALIFORNIA GAS COMPANY
SUMMARY OF ADOPTED GAS DEMAND AND SUPPLY FORECASTS

Annual Average Demand and Supply for
BCAP Forecast Period: October 1, 1991 thru September 30, 1993

THROUGHPUT TYPE	GAS DEMAND (Mdth)	
Residential	280,264	
Commercial Core	74,855	
Commercial Noncore	20,629	
Industrial Core	30,278	
Industrial Noncore	76,067	
Retail UEG	180,911	
Commercial Cogeneration	22,000	
Industrial Cogeneration	50,000	
EOR Cogeneration	97,150	
EOR Steamflood	48,401	
Company Use	9,561	
Lost & Unaccounted for (LUAF)	12,979	
Storage Surface Losses	139	
Wholesale - Long Beach	29,704	
Wholesale - San Diego	111,050	
Total Sales and Transport	1,043,987	Mdth
Exchange	31,676	
Interutility Transport	4,749	
TOTAL GAS DEMAND	1,080,412	Mdth
TOTAL DELIVERABLE GAS SUPPLIES	1,076,814	Mdth
Average year curtailments	3,599	Mdth

NOTE: Curtailments reflect localized EOR distribution bottlenecks in first BCAP year.

TABLE 2

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND AND SUPPLY FORECASTS BY CUSTOMER CLASS

Annual Average Demand and Supply for
BCAP Forecast Period: October 1, 1991 thru September 30, 1993

CLASS/SCHEDULE	PRIORITY	SERVICE LEVEL	DEMAND FORECAST (Mdth)	CURTAILMENT FORECAST (Mdth)	SUPPLY FORECAST (Mdth)
RESIDENTIAL GR,GS,GM	P-1	1	278,470		278,470
RESIDENTIAL GT-10	P-1	1	1,794		1,794
TOTAL RESIDENTIAL			280,264	0	280,264
COMMERCIAL GN-10C	P-1	1	66,449		66,449
COMMERCIAL GN-20C	P-2A	1	3,990		3,990
COMMERCIAL GT-10	P-2A	1	4,249		4,249
COMMERCIAL GN-20T	P-2A	1	168		168
COMMERCIAL GN-30	P-2B	2	1,211		1,211
COMMERCIAL GT-30	P-2B	2	84		84
COMMERCIAL GN-30E	P-2B	2	443		443
COMMERCIAL GN-30T	P-2B	3	534		534
COMMERCIAL GN-30T	P-2B	2	549		549
COMMERCIAL GN-10C	P-3A	1	238		238
COMMERCIAL GN-20C	P-3A	1	127		127
COMMERCIAL GT-20	P-3A	1	140		140
COMMERCIAL GT-30	P-3A	2	1,071		1,071
COMMERCIAL GN-30E	P-3A	2	470		470
COMMERCIAL GN-50E	P-3A	2	1,394		1,394
COMMERCIAL GT-50	P-3A	2	5,608		5,608
COMMERCIAL GN-30T	P-3A	3	1,043		1,043
COMMERCIAL GN-50T	P-3A	3	9,219		9,219
COMMERCIAL GN-50T	P-3A	5	237		237
COMMERCIAL GN-50T(L)	P-3A	2	2,454		2,454
COMMERCIAL GN-50T(L)	P-3A	3	0		0
COMMERCIAL GN-30E	P-3B	2	2,310		2,310
COMMERCIAL GT-30	P-3B	2	7,231		7,231
COMMERCIAL GN-30T	P-3B	3	2,084		2,084
COMMERCIAL GN-30E	P-4	2	1,487		1,487
COMMERCIAL GT-30	P-4	2	4,588		4,588
COMMERCIAL GN-30T	P-4	3	108		108
TOTAL COMMERCIAL			117,485	0	117,485
SPCL CUST GN-20N	P-2A	1	72		72
INDUSTRIAL GN-10C	P-1	1	20,270		20,270
INDUSTRIAL GT-10	P-1	1	616		616
INDUSTRIAL GN-20C&E	P-2A	1	8,782		8,782
INDUSTRIAL GN-20C	P-2B	1	39		39
INDUSTRIAL GN-20T	P-2A	1	499		499
INDUSTRIAL GN-30	P-2B	2	4,268		4,268
INDUSTRIAL GT-30	P-2B	2	998		998
INDUSTRIAL GN-20E	P-2B	1	0		0
INDUSTRIAL GN-20T	P-2B	1	0		0
INDUSTRIAL GN-30E	P-2B	2	3,131		3,131
INDUSTRIAL GT-30	P-2B	2	5,583		5,583
INDUSTRIAL GN-30T	P-2B	3	7,083		7,083
INDUSTRIAL GT-30	P-2B	4	52		52
INDUSTRIAL GT-30	P-2B	5	0		0
INDUSTRIAL GN-10C	P-3A	1	43		43
INDUSTRIAL GN-20N	P-3A	1	0		0
INDUSTRIAL GT-20	P-3A	1	0		0
INDUSTRIAL GN-30E	P-3A	2	40		40
INDUSTRIAL GT-30	P-3A	2	1,843		1,843

TABLE 2 (Cont)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND AND SUPPLY FORECASTS BY CUSTOMER CLASS

Annual Average Demand and Supply for
BCAP Forecast Period: October 1, 1991 thru September 30, 1993

CLASS/SCHEDULE	PRIORITY	SERVICE LEVEL	DEMAND FORECAST (Mdth)	CURTAILMENT FORECAST (Mdth)	SUPPLY FORECAST (Mdth)
INDUSTRIAL GN-50E	P-3A	2	141		141
INDUSTRIAL GT-50	P-3A	2	9,236		9,236
INDUSTRIAL GN-30T	P-3A	3	3,362		3,362
INDUSTRIAL GN-50T	P-3A	3	35,154		35,154
INDUSTRIAL GN-50T	P-3A	5	181		181
INDUSTRIAL GN-50T(L)	P-3A	2	0		0
INDUSTRIAL GN-50T(L)	P-3A	3	0		0
EOR COGEN GT-40	P-3A	2	989		989
EOR COGEN GT-40	P-3A	3	928		928
EOR COGEN GT-40	P-3A	5	132		132
EOR COGEN GLT-40	P-3A	2	785		785
EOR COGEN GLT-40	P-3A	3	94,317		94,317
INDUSTRIAL GN-30E	P-3B	2	3,972		3,972
INDUSTRIAL GT-30	P-3B	2	17,526		17,526
INDUSTRIAL GN-30T	P-3B	3	19,906		19,906
INDUSTRIAL GT-30	P-3B	4	0		0
INDUSTRIAL GT-30	P-3B	5	0		0
INDUSTRIAL GN-30E	P-4	2	59		59
INDUSTRIAL GN-30T	P-4	3	4,429		4,429
INDUSTRIAL GT-30	P-4	2	3,444		3,444
INDUSTRIAL GT-30	P-4	4	0		0
INDUSTRIAL GT-30	P-4	5	0		0
EOR STEAM GT-40	P-5	2	813		813
EOR STEAM GT-40	P-5	3	432		432
EOR STEAM GT-40	P-5	4	410		410
EOR STEAM GT-40	P-5	5	11,601	(2,027)	9,575
EOR STEAM GLT-40	P-5	3	22,317	(5)	22,312
EOR STEAM GLT-40	P-5	4	12,322	(3)	12,320
EOR STEAM GLT-40	P-5	5	508	(104)	405
SPCL CUST GT-30	P-3B	3	4,237		4,237
SPCL CUST GT-30	P-4	3	1,379		1,379
TOTAL INDUSTRIAL			301,896	(2,137)	299,759
UEG SALES GN-60C	P-2B	2	2,291		2,291
UEG TRANS GN-60T	P-2B	2	0		0
UEG GN-60T	P-3	2	33,048		33,048
UEG GN-60T	P-3C	2	9,628		9,628
UEG S-TERM GN-60T	P-5	2	88,363		88,363
UEG S-TERM GN-60T	P-5	5	47,582		47,582
TOTAL UEG			180,911	0	180,911
EXCHANGE W/OTHER UTIL	P-1	1	4,725		4,725
ONSHORE CAL. EXCH.	P-1	1	0		0
OFFSHORE P.POINT EXCH	P-1	1	0		0
ON SHORE CAL. EXCH.	P-2A	1	1,759		1,759
OFFSHORE P.POINT EXCH	P-2A	1	0		0
ONSHORE CAL. EXCH.	P-2B	3	1,590		1,590
OFFSHORE P.POINT EXCH	P-2B	3	0		0
ONSHORE CAL. EXCH.	P-3A eor	3	3,877		3,877
OFFSHORE P.POINT EXCH	P-3Aother	3	9,053		9,053
ONSHORE CAL. EXCH.	P-3B	3	5,626		5,626
OFFSHORE CAL. EXCH.	P-3B	3	0		0
OFFSHORE P.POINT EXCH	P-3B	3	0		0

TABLE 2 (Cont)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND AND SUPPLY FORECASTS BY CUSTOMER CLASS

Annual Average Demand and Supply for
BCAP Forecast Period: October 1, 1991 thru September 30, 1993

CLASS/SCHEDULE	PRIORITY	SERVICE LEVEL	DEMAND FORECAST (Mdth)	CURTAILMENT FORECAST (Mdth)	SUPPLY FORECAST (Mdth)
ONSHORE CAL. EXCH.	P-4	3	1,880		1,880
OFFSHORE P.POINT EXCH	P-4	3	0		0
ONSHORE CAL. EXCH.	P-5	3	3,169		3,169
OFFSHORE P.POINT EXCH	P-5	3	0		0
TOTAL EXCHANGE			31,676	0	31,676
FUEL USE - INJECTION	P-1	1	2,141		2,141
FUEL USE - MAINLINE	P-1	1	6,856		6,856
MISC. COMPANY USE	P-1	1	539		539
MISC. COMPANY USE	P-2A	1	25		25
TOTAL COMPANY USE			9,561	0	9,561
STORAGE SURFACE LOSSES	P-1	1	139		139
UNACCOUNTED FOR	P-1	1	12,979		12,979
TOTAL RETAIL			934,910	(2,137)	932,773
LBEACH SALES S-T TRN	P-1	1	13,347		13,347
LBEACH CO USE S-T TRN	P-1	1	0		0
LBEACH UNACCT S-T TRN	P-1	1	0		0
LESS OWN SUPPLY	P-1	1	(4,770)		(4,770)
LBEACH SALES S-T TRN	P-2A	1	648		648
LBEACH S-T TRANS	P-2B	2	328		328
LBEACH UEG S-T TRANS	P-3	5	3,102		3,102
LBEACH S-T TRANS	P-3A	5	0		0
LBEACH REG S-T TRANS	P-3B	2	2,419		2,419
LBEACH S-T TRANS	P-4	2	968		968
LBEACH UEG S-T TRANS	P-5	5	13,662		13,662
TOTAL LONG BEACH			29,704	0	29,704
SDG&E UEG FORECAST	P-5	2	0		0
SDG&E RESIDENTIAL	P-1	1	33,044		33,044
SDG&E CO USE S-T TRN	P-1	1	187		187
SDG&E UNACCT S-T TRN	P-1	1	694		694
SDG&E COMMERCIAL	P1&2A	1	11,545		11,545
SDG&E IGN S-T TRN	P-2A	1	254		254
SDG&E INDUSTRIAL	P-2B&3B&4	2	5,657		5,657
SDG&E COGENERATION	P-3A	2	17,400		17,400
SDG&E UEG	P-3	2	7,809		7,809
SDG&E STEAM	P-4	2	0		0
SDG&E UEG	P-5	5	4,093		4,093
SDG&E UEG	P-3AA	2	30,368		30,368
TOTAL SDG&E			111,050	0	111,050
TOTAL WHOLESALE			140,753	0	140,753
INTERUTILITY	P-3A,P-5	5	4,749	(1,462)	3,288
GRAND TOTAL			1,080,412	(3,599)	1,076,814

TABLE 3

SOUTHERN CALIFORNIA GAS COMPANY
SUMMARY OF ADOPTED DEMAND AND SUPPLY FORECAST BY PRIORITY AND SERVICE LEVEL

Annual Average Demand and Supply for
BCAP Forecast Period: October 1, 1991 thru September 30, 1993

PRIORITY	DEMAND FORECAST (Mdth)	CURTAILMENT FORECAST (Mdth)	SUPPLY FORECAST (Mdth)
P-1	447,928	0	447,928
P-2A	21,541	0	21,541
P-2B	29,484	0	29,484
P-3	43,959	0	43,959
P-3AA	30,368	0	30,368
P-3A	202,983	(775)	202,209
P-3B	69,668	0	69,668
P-3C	9,628	0	9,628
P-4	18,341	0	18,341
P-5	206,514	(2,824)	203,690
GRAND TOTAL	1,080,412	(3,599)	1,076,814

SERVICE LEVEL	DEMAND FORECAST (Mdth)	CURTAILMENT FORECAST (Mdth)	SUPPLY FORECAST (Mdth)
1	470,055	0	470,055
2	280,003	0	280,003
3	231,725	(5)	231,720
4	12,784	(3)	12,781
5	85,845	(3,592)	82,254
GRAND TOTAL	1,080,412	(3,599)	1,076,814

END APPENDIX D

TABLE 1

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED COSTS

Annual Average Costs for
BCAP Forecast Period: October 1, 1991 thru September 30, 1993

	VOLUME (Mdth)	PRICE ($/dth)	COST (M$)
SINGLE PORTFOLIO SUPPLIES 1/			
Elk Hills	0		0
California (NCPC)	4,205	2.1116	8,878
Other California Purchases	33,009	2.3747	78,386
Direct Purchases - SW USA	203,616	2.1402	435,789
PITCO - Pan Alberta	82,230	2.0421	167,922
POPCO - Hondo	12,865	2.3825	30,650
Federal Offshore	4,476	3.7091	16,602
Spot Market	69,536	1.8693	129,981
Total Single Portfolio purchases	409,935	2.1179	868,207
MPO Transition Cost Adjustment			(21,342)
Adjusted Single Portfolio purchases	409,935		846,864
Adjusted Single Portfolio WACOG		2.0658	
CORE STORAGE			
Storage Withdrawal	84,340	2.0658	174,233
Storage Injection	(84,620)	2.0658	(174,811)
Net storage	(280)		(578)
PIPELINE DEMAND CHARGES			
El Paso			109,906
Transwestern			86,708
PITCO - Pan Alberta			85,346
POPCO - Hondo			40,045
Total Pipeline Demand Charges			322,004
TRANSITION COSTS			
Take-or-Pay			30,384
Southland/Chevron Refund			(53,300)
El Paso Refund			(9,100)
Excess Commodity Purchases			0
MPO Transition Cost Adjustment			21,342
Total Transition Costs			(10,674)

1/ Noncore Portfolio was abolished on August 1, 1991.

TABLE 1 (cont)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED COSTS

Annual Average Costs for
BCAP Forecast Period: October 1, 1991 thru September 30, 1993

	VOLUME (Mdth)	PRICE ($/dth)	COST (M$)
BALANCING ACCOUNTS: 1/			
Core Purchased Gas Account (CPGA) 2/			(48,073)
Core Non-Gas Accounts:			
Core Fixed Cost Account (CFCA)			151,417
Core Implementation Account (CIA)			(12,247)
Conservation Cost Adjustment (CCA)			8,213
Enhanced Oil Recovery Account (EORA)			3,776
Total Core Non-Gas Account Balance			151,159
Noncore Accounts:			
Negotiated Revenue Stability Account (NRSA)			477
Enhanced Oil Recovery Account (EORA)			1,047
Noncore Implementation Account (NIA)			(6,171)
Minimum Purchase Obligation (MPO)			7,578
Pipeline Demand Charges (PDC)			822
Carrying Cost of Storage			(162)
Take-or-Pay			4,184
Noncore Fixed Cost Account (NFCA)			(1,933)
Conservation Cost Adjustment (CCA)			496
Pilot Storage Banking Account (PSBA)			(5,629)
Total Noncore Non-Gas Account Balance			709
COMPANY USE AND UNACCOUNTED FOR			
Company Use	9,561	2.0658	19,751
Lost and Unaccounted for (LUAF)	13,118	2.0658	27,101
Total Company Use & LUAF	22,679		46,852

1/ Balancing acccounts to be amortized over twelve months.

2/ Includes credits of $1.470 million and $2.229 million (plus interest) mandated by D.91-09-026, Ordering Paragraphs 2 and 3.

TABLE 2

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED SINGLE PORTFOLIO PRICE

Calculation for
BCAP Year 1: October 1, 1991 thru September 30, 1992

	VOLUME (Mdth)	PRICE ($/dth)	COST (M$)
Adjusted Single Portfolio Purchases	409,935		846,864
Net storage	(280)		(578)
Single Portfolio Demand	409,655		846,286
Less: Company use & LUAF	9,960		20,576
Plus: Core Purchased Gas Account (CPGA)			(48,073)
Subtotal			777,637
Plus: FF&U at 2.1207%			16,491
SINGLE PORTFOLIO SALES	399,695		794,128
SINGLE PORTFOLIO PRICE		$1.9868 /dth	

NOTE: Due to adopted 12-month CPGA amortization, this price applies only to the first BCAP period.

END APPENDIX E

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED REVENUE REQUIREMENT

Calculation for
BCAP Year 1: October 1, 1991 thru September 30, 1992

PROCUREMENT REVENUE REQUIREMENT		794,128
TRANSPORTATION REVENUE REQUIREMENT		
Common Distribution	409,541	
Demand Related Transmission	124,244	
Demand Related Storage	107,106	
Customer Related	712,988	
50% Administrative & General	153,786	
	-----------	1,507,664
Pipeline Demand Charges	322,004	
Add: FF&U	6,614	
	-----------	328,618
Transition Costs	(10,674)	
Add: FF&U	(219)	
	-----------	(10,894)
Women Minority Business Enterprises (WMBE)	48	
Demand Side Management	15,959	
Migration Losses	254	
Gas Loss Memo Account (GLMA)	394	
Carrying Cost of Storage	2,817	
Core Balancing Accounts 1/	151,159	
Noncore Balancing Accounts 1/	709	
Add: FF&U	3,634	
	-----------	174,974
Company Use Gas	19,751	
Lost and Unaccounted for Gas (LUAF)	27,101	
Add: FF&U	953	
	-----------	47,804
Seasonal Rate Shortfall	7,052	
Pitas Point FF&U	572	
Storage Banking Revenue	0	
Exchange Revenue	(7,493)	
Interutility Transportation Revenue (including FF&U)	1,980	
SDG&E Long-Term Contract Shortfall	2096	
	-----------	4,207
TOTAL TRANSPORTATION REVENUE REQUIREMENT		2,052,373
Brokerage Fees	563	
Net LIRA contribution to revenue requirement	(10,464)	
TOTAL REVENUE REQUIREMENT (excluding LIRA and brokerage fees)		2,846,501
TOTAL REVENUE REQUIREMENT (including LIRA and brokerage fees)		2,836,601

1/ Due to adopted 12-month balancing account amortization, these revenue requirement components apply only to the first BCAP period.

END APPENDIX F

TABLE 1

SOUTHERN CALIFORNIA GAS COMPANY
SUMMARY OF ADOPTED COST ALLOCATION

BCAP Forecast Period: October 1, 1991 thru September 30, 1993

TRANSPORTATION COST ITEM	CORE COST ($000)	NONCORE COST ($000)	WHOLESALE COST ($000)	SYSTEM COST ($000)
Common Distribution	350,356	59,185	0	409,541
Demand Related Transmission	58,381	47,335	18,528	124,244
Demand Related Storage	60,896	29,602	16,608	107,106
Customer Related	699,217	11,312	2,459	712,988
50% Administrative & General	79,716	70,706	3,363	153,786
SUBTOTAL - Base Revenue	1,248,565	218,140	40,958	1,507,664
Net EOR Adjustment	(44,072)	47,041	(2,969)	(0)
Interutility Transport Revenue	874	789	317	1,980
Exchange Revenue	(3,445)	(2,827)	(1,221)	(7,493)
Storage Banking Revenue	0	0	0	0
TOTAL - Adjusted Base Revenue	1,201,922	263,143	37,085	1,502,151
Pipeline Demand Charges	151,199	124,067	53,352	328,618
Company use & LUAF	18,086	23,149	6,570	47,804
Women and Minority Bus. Ent. (WMBE)	22	20	8	49
Carry Cost Storage Inv (CCSI)	1,929	948	0	2,877
Migration Losses	147	72	40	259
Gas Loss Memo Account (GLMA)	228	112	63	402
Demand Side Management	16,297	0	0	16,297
Pitas Point	252	228	92	572
Take-or-Pay Transition Costs	13,684	12,354	4,971	31,008
MPO Transition Cost Adjustment	9,612	8,677	3,491	21,781
Seasonal Rate Shortfall	0	7,052	0	7,052
Southland/Chevron & El Paso Refunds	(28,103)	(25,371)	(10,208)	(63,682)
TOTAL - Forecast Period Costs	1,385,274	414,449	95,464	1,895,187
BALANCING ACCOUNT AMORTIZATION - BCAP YEAR 1				
Core Fixed Cost Account (CFCA)	154,628	0	0	154,628
Core Implementation Account (CIA)	(12,507)	0	0	(12,507)
Core Conservation Cost Adjustment (CCA)	8,387	0	0	8,387
Core Enhanced Oil Recovery Account (EORA)	3,856	0	0	3,856
Noncore Negotiated Revenue Stability Acct (NRSA)	0	347	140	487
Noncore Enhanced Oil Recovery Account (EORA)	0	838	230	1,068
Noncore Implementation Account (NIA)	0	(6,302)	0	(6,302)
Noncore Minimum Purchase Obligation (MPO)	0	5,512	2,218	7,730
Noncore Pipeline Demand Charges (PDC)	0	586	252	838
Noncore Cogeneration Shortfall Account (CSA)	0	0	0	0
Noncore Carrying Cost of Storage	0	(165)	0	(165)
Noncore Take-or-Pay	0	3,043	1,224	4,268
Noncore Fixed Cost Account (NFCA)	0	(1,406)	(566)	(1,972)
Noncore Conservation Cost Adjustment (CCA)	0	507	0	507
Pilot Banking Revenues Account	0	(3,665)	(2,068)	(5,733)
SUBTOTAL - BCAP Year 1 Balancing Accounts	154,365	(705)	1,430	155,090
TOTAL - BCAP Year 1 Transportation Costs	1,539,639	413,744	96,894	2,050,277
ALLOCATION ADJUSTMENTS				
Long-Term Contract Shortfall	0	(1,800)	0	(1,800)
Long-Term Contract Spread	796	714	290	1,800
CCSI Credit to Wholesale	0	0	(44)	(44)
CCSI Whl. Credit Spread	30	14	0	44
SDG&E LTK Shortfall Account	0	0	2,096	2,096
GRAND TOTAL - BCAP YEAR 1 TRANSPORTATION COSTS	1,540,465	412,672	99,236	2,052,373

NOTE: Cost allocation reflects P2B/Industrial class discount adjustment factor of 99.4%.

TABLE 2

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED CORE CUSTOMER COST ALLOCATION

BCAP Forecast Period: October 1, 1991 thru September 30, 1993

TRANSPORTATION COST ITEM	RESIDENTIAL ($000)	COMMERCIAL ($000)	CORE TOTAL ($000)
Common Distribution	279,076	71,280	350,356
Demand Related Transmission	42,939	15,442	58,381
Demand Related Storage	47,189	13,707	60,896
Customer Related	645,238	53,978	699,217
50% Administrative & General	57,888	21,828	79,716
SUBTOTAL - Base Revenue	1,072,330	176,235	1,248,565
Net EOR Adjustment	(37,264)	(6,808)	(44,072)
Interutility Transport Revenue	634	239	874
Exchange Revenue	(2,534)	(911)	(3,445)
Storage Banking Revenue	0	0	0
TOTAL - Adjusted Base Revenue	1,033,167	168,755	1,201,922
Pipeline Demand Charges	111,207	39,992	151,199
Company use & LUAF	13,134	4,952	18,086
Women and Minority Bus. Ent. (WMBE)	16	6	22
Carry Cost Storage Inv (CCSI)	1,495	434	1,929
Migration Losses	114	33	147
Gas Loss Memo Account (GLMA)	176	51	228
Demand Side Management	11,835	4,463	16,297
Pitas Point	183	69	252
Take-or-Pay Transition Costs	9,937	3,747	13,684
MPO Transition Cost Adjustment	6,980	2,632	9,612
Seasonal Rate Shortfall	0	0	0
Southland/Chevron & El Paso Refunds	(20,408)	(7,695)	(28,103)
TOTAL - Forecast Period Costs	1,167,836	217,439	1,385,274
BALANCING ACCOUNT AMORTIZATION - BCAP YEAR 1			
Core Fixed Cost Account (CFCA)	112,287	42,341	154,628
Core Implementation Account (CIA)	(9,082)	(3,425)	(12,507)
Core Conservation Cost Adjustment (CCA)	6,091	2,297	8,387
Core Enhanced Oil Recovery Account (EORA)	3,260	596	3,856
Noncore Negotiated Revenue Stability Acct (NRSA)	0	0	0
Noncore Enhanced Oil Recovery Account (EORA)	0	0	0
Noncore Implementation Account (NIA)	0	0	0
Noncore Minimum Purchase Obligation (MPO)	0	0	0
Noncore Pipeline Demand Charges (PDC)	0	0	0
Noncore Cogeneration Shortfall Account (CSA)	0	0	0
Noncore Carrying Cost of Storage	0	0	0
Noncore Take-or-Pay	0	0	0
Noncore Fixed Cost Account (NFCA)	0	0	0
Noncore Conservation Cost Adjustment (CCA)	0	0	0
Pilot Banking Revenues Account	0	0	0
SUBTOTAL - BCAP Year 1 Balancing Accounts	112,556	41,808	154,365
TOTAL - BCAP Year 1 Transportation Costs	1,280,392	259,247	1,539,639
ALLOCATION ADJUSTMENTS			
Long-Term Contract Shortfall	0	0	0
Long-Term Contract Spread	578	218	796
CCSI Credit to Wholesale	0	0	0
CCSI Whl. Credit Spread	23	7	30
SDG&E LTK Shortfall Account	0	0	0
GRAND TOTAL - BCAP YEAR 1 TRANSPORTATION COSTS	1,280,993	259,472	1,540,465

TABLE 3

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED NONCORE CUSTOMER COST ALLOCATION

BCAP Forecast Period: October 1, 1991 thru September 30, 1993

TRANSPORTATION COST ITEM	P2B/LARGE INDUSTRIAL ($000)	CONTRACT INDUSTRIAL ($000)	EOR/ EOR COGEN ($000)	CONTRACT COGEN ($000)
Common Distribution	44,213	0	0	580
Demand Related Transmission	14,153	0	0	335
Demand Related Storage	9,901	0	0	230
Customer Related	6,301	0	0	64
50% Administrative & General	20,198	0	0	509
SUBTOTAL - Base Revenue	94,766	0	0	1,717
Net EOR Adjustment	(4,166)	0	57,833	(82)
Interutility Transport Revenue	235	0	0	6
Exchange Revenue	(845)	0	0	(20)
Storage Banking Revenue	0	0	0	0
TOTAL - Adjusted Base Revenue	89,990	0	57,833	1,621
Pipeline Demand Charges	37,096	0	0	878
Company use & LUAF	4,869	0	6,821	115
Women and Minority Bus. Ent. (WMBE)	6	0	0	0
Carry Cost Storage Inv (CCSI)	317	0	0	7
Migration Losses	24	0	0	1
Gas Loss Memo Account (GLMA)	37	0	0	1
Demand Side Management	0	0	0	0
Pitas Point	68	0	0	2
Take-or-Pay Transition Costs	3,684	0	0	87
MPO Transition Cost Adjustment	2,587	0	0	61
Seasonal Rate Shortfall	2,103	0	0	50
Southland/Chevron & El Paso Refunds	(7,565)	0	0	(179)
TOTAL - Forecast Period Costs	133,216	0	64,653	2,644
BALANCING ACCOUNT AMORTIZATION - BCAP YEAR 1				
Core Fixed Cost Account (CFCA)	0	0	0	0
Core Implementation Account (CIA)	0	0	0	0
Core Conservation Cost Adjustment (CCA)	0	0	0	0
Core Enhanced Oil Recovery Account (EORA)	0	0	0	0
Noncore Negotiated Revenue Stability Acct (NRSA)	103	0	0	2
Noncore Enhanced Oil Recovery Account (EORA)	324	0	0	6
Noncore Implementation Account (NIA)	(1,879)	0	0	(45)
Noncore Minimum Purchase Obligation (MPO)	1,644	0	0	39
Noncore Pipeline Demand Charges (PDC)	175	0	0	4
Noncore Cogeneration Shortfall Account (CSA)	0	0	0	0
Noncore Carrying Cost of Storage	(55)	0	0	(1)
Noncore Take-or-Pay	907	0	0	22
Noncore Fixed Cost Account (NFCA)	(419)	0	0	(10)
Noncore Conservation Cost Adjustment (CCA)	507	0	0	0
Pilot Banking Revenues Account	(1,238)	0	0	0
SUBTOTAL - BCAP Year 1 Balancing Accounts	68	0	0	18
TOTAL - BCAP Year 1 Transportation Costs	133,285	0	64,653	2,662
ALLOCATION ADJUSTMENTS				
Long-Term Contract Shortfall	0	0	0	(1,800)
Long-Term Contract Spread	214	0	0	0
CCSI Credit to Wholesale	0	0	0	0
CCSI Whl. Credit Spread	5	0	0	0
SDG&E LTK Shortfall Account	0	0	0	0
GRAND TOTAL - BCAP YEAR 1 TRANSPORTATION COSTS	133,504	0	64,653	862

TABLE 3
(cont'd)
SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED NONCORE CUSTOMER COST ALLOCATION

BCAP Forecast Period: October 1, 1991 thru September 30, 1993

TRANSPORTATION COST ITEM	NON-EOR COGEN ($000)	UEG ($000)	NONCORE TOTAL ($000)
Common Distribution	14,393	0	59,185
Demand Related Transmission	8,323	24,523	47,335
Demand Related Storage	5,704	13,768	29,602
Customer Related	1,005	3,941	11,312
50% Administrative & General	12,633	37,367	70,706
SUBTOTAL - Base Revenue	42,058	79,599	218,140
Net EOR Adjustment	(2,012)	(4,532)	47,041
Interutility Transport Revenue	138	410	789
Exchange Revenue	(497)	(1,465)	(2,827)
Storage Banking Revenue	0	0	0
TOTAL - Adjusted Base Revenue	39,687	74,012	263,143
Pipeline Demand Charges	21,816	64,276	124,067
Company use & LUAF	2,866	8,478	23,149
Women and Minority Bus. Ent. (WMBE)	3	10	20
Carry Cost Storage Inv (CCSI)	183	441	948
Migration Losses	14	34	72
Gas Loss Memo Account (GLMA)	22	52	112
Demand Side Management	0	0	0
Pitas Point	40	118	228
Take-or-Pay Transition Costs	2,169	6,414	12,354
MPO Transition Cost Adjustment	1,523	4,506	8,677
Seasonal Rate Shortfall	1,238	3,662	7,052
Southland/Chevron & El Paso Refunds	(4,454)	(13,173)	(25,371)
TOTAL - Forecast Period Costs	65,106	148,829	414,449
BALANCING ACCOUNT AMORTIZATION - BCAP YEAR 1			
Core Fixed Cost Account (CFCA)	0	0	0
Core Implementation Account (CIA)	0	0	0
Core Conservation Cost Adjustment (CCA)	0	0	0
Core Enhanced Oil Recovery Account (EORA)	0	0	0
Noncore Negotiated Revenue Stability Acct (NRSA)	61	180	347
Noncore Enhanced Oil Recovery Account (EORA)	156	352	838
Noncore Implementation Account (NIA)	(1,106)	(3,272)	(6,302)
Noncore Minimum Purchase Obligation (MPO)	968	2,862	5,512
Noncore Pipeline Demand Charges (PDC)	103	304	586
Noncore Cogeneration Shortfall Account (CSA)	0	0	0
Noncore Carrying Cost of Storage	(32)	(77)	(165)
Noncore Take-or-Pay	534	1,580	3,043
Noncore Fixed Cost Account (NFCA)	(247)	(730)	(1,406)
Noncore Conservation Cost Adjustment (CCA)	0	0	507
Pilot Banking Revenues Account	(713)	(1,714)	(3,665)
SUBTOTAL - BCAP Year 1 Balancing Accounts	(276)	(515)	(705)
TOTAL - BCAP Year 1 Transportation Costs	64,831	148,314	413,744
ALLOCATION ADJUSTMENTS			
Long-Term Contract Shortfall	0	0	(1,800)
Long-Term Contract Spread	126	373	714
CCSI Credit to Wholesale	0	0	0
CCSI Whl. Credit Spread	3	7	14
SDG&E LTK Shortfall Account	0	0	0
GRAND TOTAL - BCAP YEAR 1 TRANSPORTATION COSTS	64,960	148,694	412,672

TABLE 4

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED WHOLESALE CUSTOMER COST ALLOCATION

BCAP Forecast Period: October 1, 1991 thru September 30, 1993

TRANSPORTATION COST ITEM	LONG BEACH ($000)	SAN DIEGO ($000)	WHOLESALE TOTAL ($000)
Common Distribution	0	0	0
Demand Related Transmission	4,060	14,468	18,528
Demand Related Storage	3,081	13,527	16,608
Customer Related	299	2,160	2,459
50% Administrative & General	658	2,705	3,363
SUBTOTAL - Base Revenue	8,098	32,860	40,958
Net EOR Adjustment	(589)	(2,381)	(2,969)
Interutility Transport Revenue	67	250	317
Exchange Revenue	(242)	(978)	(1,221)
Storage Banking Revenue	0	0	0
TOTAL - Adjusted Base Revenue	7,334	29,752	37,085
Pipeline Demand Charges	10,598	42,755	53,352
Company use & LUAF	1,386	5,183	6,570
Women and Minority Bus. Ent. (WMBE)	2	6	8
Carry Cost Storage Inv (CCSI)	0	0	0
Migration Losses	7	33	40
Gas Loss Memo Account (GLMA)	12	51	63
Demand Side Management	0	0	0
Pitas Point	19	73	92
Take-or-Pay Transition Costs	1,049	3,922	4,971
MPO Transition Cost Adjustment	737	2,755	3,491
Seasonal Rate Shortfall	0	0	0
Southland/Chevron & El Paso Refunds	(2,154)	(8,054)	(10,208)
TOTAL - Forecast Period Costs	18,989	76,474	95,464
BALANCING ACCOUNT AMORTIZATION - BCAP YEAR 1			
Core Fixed Cost Account (CFCA)	0	0	0
Core Implementation Account (CIA)	0	0	0
Core Conservation Cost Adjustment (CCA)	0	0	0
Core Enhanced Oil Recovery Account (EORA)	0	0	0
Noncore Negotiated Revenue Stability Acct (NRSA)	29	110	140
Noncore Enhanced Oil Recovery Account (EORA)	46	184	230
Noncore Implementation Account (NIA)	0	0	0
Noncore Minimum Purchase Obligation (MPO)	468	1,750	2,218
Noncore Pipeline Demand Charges (PDC)	50	202	252
Noncore Cogeneration Shortfall Account (CSA)	0	0	0
Noncore Carrying Cost of Storage	0	0	0
Noncore Take-or-Pay	258	966	1,224
Noncore Fixed Cost Account (NFCA)	(119)	(446)	(566)
Noncore Conservation Cost Adjustment (CCA)	0	0	0
Pilot Banking Revenues Account	(384)	(1,684)	(2,068)
SUBTOTAL - BCAP Year 1 Balancing Accounts	349	1,082	1,430
TOTAL - BCAP Year 1 Transportation Costs	19,338	77,556	96,894
ALLOCATION ADJUSTMENTS			
Long-Term Contract Shortfall	0	0	0
Long-Term Contract Spread	61	229	290
CCSI Credit to Wholesale	(44)	0	(44)
CCSI Whl. Credit Spread	0	0	0
SDG&E LTK Shortfall Account	0	2,096	2,096
GRAND TOTAL - BCAP YEAR 1 TRANSPORTATION COSTS	19,355	79,881	99,236

END APPENDIX G

TABLE 1

SOUTHERN CALIFORNIA GAS COMPANY
CORE BUNDLED RATES AND REVENUES

Effective January 1, 1992

Core Customer Class	Throughput (Mth)	Present Rates ($/unit)	Present Revenues ($M)	Adopted Rate Non-Gas ($/th)	Adopted Rate Gas ($/th)	Adopted Rate Total ($/unit)	Adopted Revenue Non-Gas ($M)	Adopted Revenue Gas ($M)	Adopted Revenue Total ($M)	Change (%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
RESIDENTIAL										
Customer Charge		3.10	168,384			3.10	168,384		168,384	0.0%
Submeter Discount		6.36	(5,210)			6.36	(5,210)		(5,210)	0.0%
Subtotal			163,175				163,175		163,175	0.0%
Tier 1	1,811,168	0.48090	870,990	0.26886	0.19868	0.46755	486,958	359,849	846,807	-2.8%
Tier 2	973,534	0.80088	779,684	0.47390	0.19868	0.67258	461,359	193,425	654,784	-16.0%
TOTAL RESIDENTIAL	2,784,702	0.65136	1,813,849	0.39914	0.19868	0.59783	1,111,491	553,274	1,664,765	-8.2%
CORE COMMERCIAL										
Customer Charge - P1		10	26,442			13	34,375		34,375	30.0%
Customer Charge - P2		50	335			65	435		435	30.0%
Volumetric Charge										
Summer Tier 1	381,193	0.60181	229,406	0.33853	0.19868	0.53722	129,047	75,737	204,783	-10.7%
Summer Tier 2	192,915	0.53681	103,558	0.27353	0.19868	0.47222	52,769	38,329	91,098	-12.0%
Winter Tier 1	310,127	0.73478	227,875	0.47150	0.19868	0.67019	146,226	61,617	207,844	-8.8%
Winter Tier 2	115,855	0.57682	66,827	0.31354	0.19868	0.51223	36,326	23,018	59,344	-11.2%
TOTAL CORE COMMERCIAL	1,000,090	0.65439	654,444	0.39914	0.19868	0.59783	399,178	198,701	597,879	-8.6%
TRANSPORTATION ONLY	74,649	0.32964	24,607	0.39914	0.00000	0.39914	29,796	0	29,796	21.1%
CORE TOTAL	3,859,440	0.64592	2,492,900	0.39914	0.19484	0.59398	1,540,465	751,975	2,292,440	-8.0%

RESIDENTIAL LOW INCOME RATEPAYER ASSISTANCE (LIRA)

Adopted LIRA Rates and Discounts	LIRA Throughput (Mth)	Non-LIRA Rate ($/unit)	LIRA Rate ($/unit)	Rate Discount ($/unit)	Revenue Discount ($M)
Customer Charge		3.10	2.64	0.46	2,108
Submetering Adjustment					62
Tier 1	106,491	0.46755	0.39742	0.07013	7,468
Tier 2	57,240	0.67258	0.57170	0.10089	5,775
Total	163,731				15,413

LIRA Surcharge Calculation		
LIRA Benefit	($M)	15,413
LIRA A&G	($M)	996
LIRA Balancing Acct	($M)	(11,460)
Total LIRA Cost	($M)	4,949
Nonexempt Volumes	(Mth)	4,735,805
LIRA Surcharge	($/th)	0.00105

TABLE 2

SOUTHERN CALIFORNIA GAS COMPANY
NONCORE DEFAULT TRANSPORT RATES AND REVENUES

Effective January 1, 1992

Noncore Customer Class	Throughput (Mth)	Present Rates ($/th)	Present Revenues ($M)	Adopted Rates ($/th)	Adopted Revenues ($M)	Absolute Change ($M)	Relative Change (%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
INDUSTRIAL							
Customer Charge			3,036		4,998	1,962	64.6%
Volumetric Charge							
Summer	678,150	0.07964	54,008	0.11385	77,204	23,197	43.0%
Winter	360,767	0.10913	39,370	0.14220	51,301	11,931	30.3%
Volumetric Subtotal	1,038,917	0.08988	93,378	0.12369	128,505	35,127	37.6%
TOTAL INDUSTRIAL	1,038,917	0.09280	96,414	0.12850	133,504	37,089	38.5%
UTILITY ELECTRIC GENERATION (UEG) 1/							
Facilities Charges					1,078		
Volumetric Charge 2/							
Summer	1,300,555	0.05696	74,081	0.07978	103,752	29,671	40.1%
Winter	508,550	0.07753	39,426	0.10784	54,841	15,415	39.1%
Volumetric Subtotal	1,809,105	0.06274	113,508	0.08766	158,593	45,086	39.7%
TOTAL UEG	1,809,105	0.06274	113,508	0.08826	159,672	46,164	40.7%
COGENERATION							
Volumetric Charge							
Summer	403,329	0.05707	23,018	0.07870	31,743	8,725	37.9%
Winter	208,287	0.07736	16,113	0.10677	22,238	6,125	38.0%
Volumetric Subtotal	611,616	0.06398	39,131	0.08826	53,981	14,850	38.0%
Cogeneration LT Contracts	24,623	0.04020	990	0.03501	862	(128)	-12.9%
TOTAL COGENERATION	636,239	0.06306	40,121	0.08620	54,843	14,722	36.7%
NONCORE SUBTOTAL							
Net of LT Contracts	3,459,638	0.07199	249,053	0.10034	347,157	98,104	39.4%
Including LT Contracts	3,484,261	0.07176	250,043	0.09988	348,019	97,976	39.2%
WHOLESALE							
Long Beach							
Demand Charge			2,251		10,444	8,193	364.0%
Volumetric Charge							
Summer	182,690	0.05696	10,406				
Winter	114,345	0.06626	7,576				
Annual	297,035		17,983	0.03000	8,911	(9,072)	-50.4%
Total Long Beach	297,035	0.06812	20,234	0.06516	19,355	(878)	-4.3%
SDG&E							
Demand Charge	1,110,498		69,616		63,887	(5,729)	-8.2%
Volumetric Tier 1	793,328	0.00785	6,228	0.00794	6,296	68	1.1%
Volumetric Tier 2	267,044	0.02697	7,202	0.02698	7,204	2	0.0%
Volumetric Tier 3	50,126	0.00785	393	0.00794	398	4	1.1%
Contract Shortfall					2,096	2,096	
Total SDG&E	1,110,498	0.07514	83,439	0.07193	79,881	(3,558)	-4.3%
TOTAL WHOLESALE	1,407,533	0.07366	103,673	0.07050	99,236	(4,437)	-4.3%
NONCORE TOTAL							
Net of LT Contracts	4,867,171	0.07247	352,726	0.09172	446,393	93,667	26.6%
Include LT Contracts	4,891,794	0.07231	353,716	0.09143	447,255	93,539	26.4%
BROKERAGE	212,160	0.00266	563	0.00266	563	0	0.0%

1/ The default UEG rate design applies to about 10% of forecast UEG throughput, due to recently-amended service agreements with Edison and LADWP. The contracts feature non-seasonally-differentiated tailblock volumetric rates of 0.03 $/th. Edison's residual seasonal allocated cost obligation is recovered through monthly demand charges, while LADWP's is collected via a higher Tier I (18.5% of forecast monthly demand) volumetric rate. Both agreements expire upon implementation of capacity brokering, or 9/30/93, whichever occurs first.

2/ Since Igniter Fuel (formerly P-2A) has been declared noncore, present rates include prorated igniter revenue at 34.157 cents/therm.

TABLE 3

ADOPTED INTERRUPTIBLE SERVICE RATE CREDIT

Effective January 1, 1992

Customer Class	NONCORE AVG. YEAR THROUGHPUT Service Level 2 (Mth)	Service Level 3-5 (Mth)	Total (Mth)
Industrial	603,069	442,183	1,045,252
Cogeneration	188,329	423,287	611,616
UEG	1,333,290	475,815	1,809,105
Wholesale (Long B. Only)	37,150	167,640	204,790
Total/Average	2,161,838	1,508,925	3,670,763
Service Level 2 Premium ($/th)			0.01200
Service Level 2 Revenues ($M)			25,942
Interruptable credit to SL 3-5 ($/th)			0.01719

END APPENDIX H

TABLE 1

SAN DIEGO GAS & ELECTRIC COMPANY
ANNUAL AVERAGE GAS DEMAND

BCAP Forecast Period: October 1, 1991 to September 30, 1993

THROUGHPUT CATEGORY	DEMAND FORECAST (M Therms)
Residential	330,442
Commercial	115,458
Industrial	67,608
UEG	424,589
Cogeneration	160,450
Company Use	2,922
Loss and Unaccounted For	7,618
TOTAL DEMAND	1,109,087

TABLE 2

SAN DIEGO GAS & ELECTRIC COMPANY
ANNUAL AVERAGE SUPPLY FORECAST BY CUSTOMER CLASS AND PRIORITY

BCAP Forecast Period: October 1, 1991 to September 30, 1993

CUSTOMER CLASS	PRIORITY	SUPPLY FORECASTS (M Therms)
Residential	P-1	330,442
Commercial	P-1	102,998
Commercial	P-2A	12,460
Industrial	P-2B	6,288
Industrial	P-3B	54,275
Industrial	P-4	7,045
Cogeneration	P-3A	160,450
UEG	P-2A	3,142
UEG	P-3B	340
UEG	P-5	421,107
Company Use	P-1	2,922
Unaccounted For	P-1	7,618
TOTAL SUPPLY		1,109,087

TABLE 3

SAN DIEGO GAS & ELECTRIC COMPANY
ANNUAL AVERAGE SUPPLY FORECAST BY SUB-ACCOUNT

BCAP Forecast Period: October 1, 1991 to September 30, 1993

SUB-ACCOUNT	SUPPLY FORECASTS (M Therms)
CORE SALES	
Residential	327,702
Commercial--GN1	102,995
Commercial--GN2A	8,916
Industrial	2,420
Cogeneration	460
	442,492
NONCORE SALES	
Commercial--Igniter	2,527
Industrial	60,572
Cogeneration	97,665
UEG--GN5	424,589
	585,354
TRANSPORTATION	
Residential	2,740
Commercial--GN1	3
Commercial--GN2A & Igniter	1,018
Industrial	4,615
Cogeneration	62,325
	70,702
COMPANY USE	2,922
LOSS AND UNACCOUNTED FOR	7,618
TOTAL SUPPLY	1,109,087

TABLE 4

SAN DIEGO GAS & ELECTRIC COMPANY
GAS PROCUREMENT RATES

BCAP Forecast Period: October 1, 1991 to September 30, 1993

(Dollars in Thousands)	CORE & CORE-SUB.	RETAIL NONCORE	UEG & IGNITER	TOTAL
Annual Average Sales Volume (MMth)	442,492	158,238	427,116	1,027,846
WACOG Price (cents/therm)	22.26	22.26	22.26	22.26
Commodity Cost of Gas	$98,477	$35,216	$95,055	$228,747
Core Purchased Gas Account (PGA)	($14,721)	$0	$0	($14,721)
Subtotal	$83,756	$35,216	$95,055	$214,026
F&U @ 2.490%	$2,086	$877	$0	$2,962
Procurement Revenue	$85,841	$36,093	$95,055	$216,988
PROCUREMENT RATE (CENTS/THERM)	19.399	22.809	22.255	21.111

TABLE 1a

SAN DIEGO GAS & ELECTRIC COMPANY
ADOPTED REVENUE REQUIREMENTS

BCAP Forecast Period 1: October 1, 1991 to September 30, 1992

REVENUE REQUIREMENT (Dollars in Thousands)	SOCALGAS ALLOCATED COSTS	SDG&E COSTS	SYSTEM TOTAL COSTS
PROCUREMENT REVENUE REQUIREMENT			
Commodity Cost of Gas	$0.0	$228,747.0	$228,747.0
Core Purchase Gas Account (CPGA)	0.0	(14,721.0)	(14,721.0)
Franchise and Uncollectibles (F&U)	0.0	2,976.4	2,976.4
TOTAL PROCUREMENT REVENUE REQUIREMENT	0.0	217,002.4	217,002.4
TRANSMISSION REVENUE REQUIRMENT			
Authorized Gas Margin			
*Common Distribution	0.0	52,459.0	52,459.0
*Demand Related Transmission	14,468.0	10,774.0	25,242.0
*Demand Related Storage	13,527.0	692.0	14,219.0
*Customer Related Distribution	0.0	80,528.0	80,528.0
Customer Related Transmission	2,160.0	0.0	2,160.0
*Commodity Related	0.0	1,879.0	1,879.0
*50% Administrative & General Expenses	2,705.0	11,997.0	14,702.0
Pipeline Demand Charge	42,755.0	0.0	42,755.0
DSM Collaborative	0.0	507.0	507.0
Net EOR Adjustment	(2,381.0)	0.0	(2,381.0)
Contract Adjustment (SDG&E)	0.0	0.0	0.0
	73,234.0	158,836.0	232,070.0
TRANSITION COSTS			
Take-or-Pay	3,922.0	0.0	3,922.0
Excess Commodity Purchases	0.0	0.0	0.0
El Paso/Chevron Refund	(8,054.0)	0.0	(8,054.0)
Minimum Purchase Obligation	2,755.0	0.0	2,755.0
	(1,377.0)	0.0	(1,377.0)
SDG&E BALANCING AND TRACKING ACCOUNTS			
CSA Cogeneration Shortfall Account	0.0	0.0	0.0
CFCA Core Fixed Cost Account	0.0	9,897.0	9,897.0
NTCA Noncore Transition Cost Account	0.0	0.0	0.0
CIBA Core Implementation Balancing Account	0.0	(1,412.0)	(1,412.0)
NIBA Noncore Implementation Balancing Acct	0.0	(1,092.0)	(1,092.0)
CCSI Carrying Cost of Storage Inventory	0.0	0.0	0.0
NRSA Negotiated Revenue Stability Account	0.0	0.0	0.0
GEBA DSM Balancing Account	0.0	3,368.0	3,368.0
F&U Franchise and Uncollectibles	0.0	285.6	285.6
	0.0	11,046.6	11,046.6

* Adjusted for 1992 attrition by equal percent of existing margin.

TABLE 1b

SAN DIEGO GAS & ELECTRIC COMPANY
ADOPTED REVENUE REQUIREMENTS

BCAP Forecast Period 1: October 1, 1991 to September 30, 1992

REVENUE REQUIREMENT (Dollars in Thousands)	SOCALGAS ALLOCATED COSTS	SDG&E COSTS	SYSTEM TOTAL COSTS
SOCALGAS BALANCING AND TRACKING ACCOUNTS ALLOCATED TO SDG&E			
Noncore Transition Cost Account	$0.0	$0.0	$0.0
Negotiated Revenue Stability Account	110.0	0.0	110.0
Pipeline Demand Charges	202.0	0.0	202.0
Minimum Purchase Obligation	1,750.0	0.0	1,750.0
Carrying Cost of Gas Storage	0.0	0.0	0.0
Noncore Fixed Cost Account	(446.0)	0.0	(446.0)
Pilot Storage Banking	(1,684.0)	0.0	(1,684.0)
Enhanced Oil Recovery Tracking Account	184.0	0.0	184.0
Take-or-Pay Obligation	966.0	0.0	966.0
	1,082.0	0.0	1,082.0
OTHER FORECASTED COSTS			
Lost and Unaccounted For Gas (LUAF)	2,998.0	1,470.0	4,468.0
Company Use	2,185.0	391.0	2,576.0
CCSI/Migration Losses/Gas Loss Memo Account	84.0	1,332.0	1,416.0
Carrying Cost of Storage-Credit to Wholesale	(511.0)	0.0	(511.0)
Exchange Revenue	(978.0)	0.0	(978.0)
Interutility Transportation Revenue	250.0	0.0	250.0
Long-Term Contract Spread	229.0	0.0	229.0
SDG&E/SoCal Reconciliation	2,607.0	0.0	2,607.0
SDG&E/SoCal Moreno Credit	0.0	0.0	0.0
Pitas Point Shortfall	73.0	0.0	73.0
Storage Banking Revenue	0.0	0.0	0.0
Women & Minority Business Enterprises	6.0	0.0	6.0
F&U on SDG&E Other Costs	0.0	53.5	53.5
F&U on SoCalGas Allocated Other Costs	0.0	1,358.0	1,358.0
	6,943.0	4,604.5	11,547.5
TRANSMISSION REVENUE REQUIREMENT	79,882.0	174,487.1	254,369.1
MISCELLANEOUS REVENUE	0.0	(3,152.0)	(3,152.0)
TOTAL TRANSMISSION REVENUE REQUIRMENT	79,882.0	171,335.1	251,217.1
TOTAL PROCUREMENT REVENUE REQUIREMENT	0.0	217,002.4	217,002.4
NET LIRA COSTS	0.0	(2,328.6)	(2,328.6)
NET REVENUE REQUIREMENT	$79,882.0	$386,009.0	$465,891.0

TABLE 2

SAN DIEGO GAS & ELECTRIC COMPANY
CORE CUSTOMER COST ALLOCATION

BCAP Forecast Period 1: October 1, 1991 to September 30, 1992

TRANSMISSION REVENUE REQUIRMENT (Dollars in Thousands)	RESIDENTIAL	COMMERCIAL (GN-1)	COMM'L (GN-2A (& UEG IGNITER)	TOTAL CORE
AUTHORIZED GAS MARGIN				
Common Distribution	$32,063.4	$7,425.9	$697.0	$40,186.2
Demand Related Transmission	8,511.4	2,414.7	280.1	11,206.2
Demand Related Storage	6,391.2	1,539.6	144.7	8,075.5
Customer Related Distribution	75,504.7	3,936.4	41.9	79,483.0
Customer Related Transmission	728.3	206.6	24.0	958.9
Commodity Related	565.2	176.2	21.3	762.7
50% Administrative & General Expenses	4,422.3	1,378.4	166.8	5,967.5
Pipeline Demand Charge	14,416.7	4,090.0	474.4	18,981.1
DSM Collaborative	377.9	118.8	10.3	507.0
Net EOR Adjustment	(847.6)	(233.0)	(26.0)	(1,106.6)
Contract Adjustment (SDG&E)	0.0	0.0	0.0	0.0
	142,133.6	21,053.6	1,834.3	165,021.6
TRANSITION COSTS				
Take-or-Pay	1,179.7	367.7	44.5	1,591.9
Excess Commodity Purchases	0.0	0.0	0.0	0.0
El Paso/Chevron Refund	(2,422.6)	(755.1)	(91.4)	(3,269.1)
Minimum Purchase Obligation	828.7	258.3	31.2	1,118.3
	(414.2)	(129.1)	(15.6)	(558.9)
SDG&E BALANCING AND TRACKING ACCOUNTS				
CSA Cogeneration Shortfall Account	0.0	0.0	0.0	0.0
CFCA Core Fixed Cost Account	7,334.3	2,286.1	276.6	9,897.0
NTCA Noncore Transition Cost Account	0.0	0.0	0.0	0.0
CIBA Core Implementation Balancing Account	(1,046.4)	(326.2)	(39.5)	(1,412.0)
NIBA Noncore Implementation Balancing Acct	0.0	0.0	0.0	0.0
CCSI Carrying Cost of Storage Inventory	0.0	0.0	0.0	0.0
NRSA Negotiated Revenue Stability Account	0.0	0.0	0.0	0.0
GEBA DSM Balancing Account	2,510.6	789.1	68.3	3,368.0
F&U Franchise and Uncollectibles	219.1	68.5	7.6	295.1
SOCALGAS BALANCING AND TRACKING ACCOUNTS ALLOCATED TO SDG&E				
Noncore Transition Cost Account	0.0	0.0	0.0	0.0
Negotiated Revenue Stability Account	33.1	10.3	1.2	44.6
Pipeline Demand Charges	68.1	19.3	2.2	89.7
Minimum Purchase Obligation	526.4	164.1	19.8	710.3
Carrying Cost of Gas Storage	0.0	0.0	0.0	0.0
Noncore Fixed Cost Account	(134.2)	(41.8)	(5.1)	(181.0)
Pilot Storage Banking	(756.9)	(182.3)	(17.1)	(956.4)
Enhanced Oil Recovery Tracking Account	65.5	18.0	2.0	85.5
Take-or-Pay Obligation	290.6	90.6	11.0	392.1
	9,110.2	2,895.6	327.1	12,333.0
OTHER FORECASTED COSTS				
Lost and Unaccounted For Gas (LUAF)	1,344.0	418.9	50.7	1,813.6
Company Use	774.9	241.5	29.2	1,045.6
CCSI/Migration Losses/Gas Loss Memo Account	636.5	153.3	14.4	804.2
Carrying Cost of Storage-Credit to Wholesale	(229.7)	(55.3)	(5.2)	(290.2)
Exchange Revenue	(329.8)	(93.6)	(10.9)	(434.2)
Interutility Transportation Revenue	84.3	23.9	2.8	111.0
Long-Term Contract Spread	68.9	21.5	2.6	93.0
SDG&E/SoCal Reconciliation	784.2	244.4	29.6	1,058.2
SDG&E/SoCal Moreno Credit	0.0	0.0	0.0	0.0
Pitas Point Shortfall	22.0	6.8	0.8	29.6
Storage Banking Revenue	0.0	0.0	0.0	0.0
Women & Minority Business Enterprises	1.8	0.6	0.1	2.4
F&U on SDG&E Other Costs	28.8	7.9	0.9	37.6
F&U on SoCalGas Allocated Other Costs	714.4	201.3	22.7	938.4
	3,900.2	1,171.3	137.7	5,209.2
TRANSMISSION REVENUE REQUIREMENT	154,729.9	24,991.4	2,283.5	182,004.8
MISCELLANEOUS REVENUE	(1,917.3)	(309.7)	(28.3)	(2,255.3)
NET LIRA COSTS	(2,164.8)	(93.0)	(9.8)	(2,267.6)
NET TRANSMISSION REVENUE REQUIREMENT	$150,647.7	$24,588.8	$2,245.4	$177,481.9

TABLE 3

SAN DIEGO GAS & ELECTRIC COMPANY
NONCORE CUSTOMER COST ALLOCATION

BCAP Forecast Period 1: October 1, 1991 to September 30, 1992

TRANSMISSION REVENUE REQUIREMENT (Dollars in Thousands)	INDUSTRIAL	COGENERATION	UEG GAS DEPT (GN3 TO GN5)	TOTAL NONCORE
AUTHORIZED GAS MARGIN				
Common Distribution	$4,088.8	$8,183.9	$0.0	$12,272.8
Demand Related Transmission	1,534.5	3,637.1	8,864.2	14,035.8
Demand Related Storage	854.7	1,815.5	3,473.4	6,143.5
Customer Related Distribution	154.0	521.3	369.7	1,045.0
Customer Related Transmission	131.3	311.2	758.5	1,201.1
Commodity Related	115.6	274.4	726.2	1,116.3
50% Administrative & General Expenses	904.8	2,147.3	5,682.3	8,734.5
Pipeline Demand Charge	2,599.1	6,160.5	15,014.3	23,773.9
DSM Collaborative	0.0	0.0	0.0	0.0
Net EOR Adjustment	(144.5)	(336.3)	(793.6)	(1,274.4)
Contract Adjustment (SDG&E)	0.0	0.0	0.0	0.0
	10,238.4	22,715.0	34,095.1	67,048.4
TRANSITION COSTS				
Take-or-Pay	241.4	572.8	1,515.9	2,330.1
Excess Commodity Purchases	0.0	0.0	0.0	0.0
El Paso/Chevron Refund	(495.7)	(1,176.3)	(3,112.9)	(4,784.9)
Minimum Purchase Obligation	169.6	402.4	1,064.8	1,636.7
	(84.7)	(201.1)	(532.2)	(818.1)
SDG&E BALANCING AND TRACKING ACCOUNTS				
CSA Cogeneration Shortfall Account	0.0	0.0	0.0	0.0
CFCA Core Fixed Cost Account	0.0	0.0	0.0	0.0
NTCA Noncore Transition Cost Account	0.0	0.0	0.0	0.0
CIBA Core Implementation Balancing Account	0.0	0.0	0.0	0.0
NIBA Noncore Implementation Balancing Acct	(113.1)	(268.5)	(710.4)	(1,092.0)
CCSI Carrying Cost of Storage Inventory	0.0	0.0	0.0	0.0
NRSA Negotiated Revenue Stability Account	0.0	0.0	0.0	0.0
GEBA DSM Balancing Account	0.0	0.0	0.0	0.0
F&U Franchise and Uncollectibles	(2.8)	(6.7)	0.0	(9.5)
SOCALGAS BALANCING & TRACKING ACCOUNTS ALLOCATED TO SDG&E				
Noncore Transition Cost Account	0.0	0.0	0.0	0.0
Negotiated Revenue Stability Account	6.8	16.1	42.5	65.4
Pipeline Demand Charges	12.3	29.1	70.9	112.3
Minimum Purchase Obligation	107.7	255.6	676.4	1,039.7
Carrying Cost of Gas Storage	0.0	0.0	0.0	0.0
Noncore Fixed Cost Account	(27.4)	(65.1)	(172.4)	(265.0)
Pilot Storage Banking	(101.2)	(215.0)	(411.4)	(727.6)
Enhanced Oil Recovery Tracking Account	11.2	26.0	61.3	98.5
Take-or-Pay Obligation	59.5	141.1	373.4	573.9
	(47.2)	(87.5)	(69.6)	(204.3)
OTHER FORECASTED COSTS				
Lost and Unaccounted For Gas (LUAF)	275.0	652.6	1,726.9	2,654.4
Company Use	158.5	376.2	995.6	1,530.4
CCSI/Migration Losses/Gas Loss Memo Account	85.1	180.8	345.9	611.8
Carrying Cost of Storage-Credit to Wholesale	(30.7)	(65.2)	(124.8)	(220.8)
Exchange Revenue	(59.5)	(140.9)	(343.4)	(543.8)
Interutility Transportation Revenue	15.2	36.0	87.8	139.0
Long-Term Contract Spread	14.1	33.4	88.5	136.0
SDG&E/SoCal Reconciliation	160.4	380.8	1,007.6	1,548.8
SDG&E/SoCal Moreno Credit	0.0	0.0	0.0	0.0
Pitas Point Shortfall	4.5	10.7	28.2	43.4
Storage Banking Revenue	0.0	0.0	0.0	0.0
Women & Minority Business Enterprises	0.4	0.9	2.3	3.6
F&U on SDG&E Other Costs	4.8	11.0	0.0	15.8
F&U on SoCalGas Allocated Other Costs	125.8	293.7	0.0	419.6
	753.7	1,770.0	3,814.6	6,338.3
TRANSMISSION REVENUE REQUIREMENT	10,860.1	24,196.4	37,307.8	72,364.3
MISCELLANEOUS REVENUE	(134.6)	(299.8)	(462.3)	(896.7)
NET LIRA COSTS	(61.0)	0.0	0.0	(61.0)
NET TRANSMISSION REVENUE REQUIREMENT	$10,664.5	$23,896.6	$36,845.5	$71,406.6

TABLE 1

SAN DIEGO GAS & ELECTRIC COMPANY
CORE BUNDLED RATES AND REVENUES

Effective January 1, 1992

CUSTOMER CLASS	THROUGHPUT	UNITS	EFFECTIVE 8/1/91 PRESENT RATES	EFFECTIVE 8/1/91 TOTAL REVENUES	EFFECTIVE 1/1/92 ADOPTED RATES	EFFECTIVE 1/1/92 TOTAL REVENUES	RATE CHANGE	PERCENT CHANGE
			C/THERM	($000)	C/THERM	($000)	C/THERM	%
RESIDENTIAL GR								
Baseline	157,290	mtherms	50.037	79,073	53.453	84,472	3.416	6.8%
Non-Baseline	85,915	mtherms	71.321	61,563	72.609	62,675	1.288	1.8%
Employee Discount				(287)		(301)		
			21.284		19.156		(2.128)	-10.0%
			1.425		1.358			
RESIDENTIAL GR-LI								
Baseline	13,746	mtherms	41.852	5,780	45.527	6,288	3.675	8.8%
Non-Baseline	4,461	mtherms	59.943	2,687	61.810	2,770	1.867	3.1%
RESIDENTIAL GS								
Regular Baseline	1,454	mtherms	50.037	730	53.453	779	3.416	6.8%
Regular Non-Baseline	363	mtherms	71.321	260	72.609	265	1.288	1.8%
LIRA Baseline	132	mtherms	41.852	55	45.527	60	3.675	8.8%
LIRA Non-Baseline	33	mtherms	59.943	20	61.810	20	1.867	3.1%
Unit Discount	69,811	Cust-mth	($1.90)	(133)	($1.90)	(133)	0.000	0.0%
RESIDENTIAL GT								
Regular Baseline	7,270	mtherms	50.037	3,642	53.453	3,890	3.416	6.8%
Regular Non-Baseline	2,974	mtherms	71.321	2,124	72.609	2,162	1.288	1.8%
LIRA Baseline	1,487	mtherms	41.852	623	45.527	678	3.675	8.8%
LIRA Non-Baseline	661	mtherms	59.943	397	61.810	409	1.867	3.1%
Unit Discount	333,271	Cust-mth	($6.00)	(2,002)	($6.00)	(2,002)	0.000	0.0%
RESIDENTIAL GM								
Baseline	42,363	mtherms	50.037	21,308	53.453	22,763	3.416	6.8%
Non-Baseline	12,292	mtherms	71.321	8,813	72.609	8,972	1.288	1.8%
RESIDENTIAL GL-1								
Facility Charge	3,792	Cust-mth	$13.82	52	$14.31	54	0.490	3.5%
Volumetric Surcharge	126	mtherms	9.653	12	16.169	20	6.516	67.5%
Less Transport-Only	(2,740)	mtherms	26.454	(728)	19.399	(534)	(7.055)	-26.7%
TOTAL RESIDENTIAL SALES	327,702	mtherms	56.145	183,989	58.989	193,309	2.844	5.1%
CORE COMMERCIAL								
GN-1 Service Charge	337,334	Cust-mth	$5.00	1,696	$5.00	1,696	0.000	0.0%
GN-2 Service Charge	264	Cust-mth	$60.00	16	$60.00	16	0.000	0.0%
Winter 0-3000 Therms	32,603	mtherms	68.541	22,469	71.774	23,529	3.233	4.7%
All Excess	16,172	mtherms	40.904	6,651	42.302	6,878	1.398	3.4%
Summer 0-3000 Therms	46,144	mtherms	58.001	26,910	60.822	28,219	2.821	4.9%
All Excess	18,013	mtherms	39.804	7,209	41.324	7,484	1.520	3.8%
Less Transport-Only	(1,021)	mtherms	26.454	(272)	19.399	(199)	(7.055)	-26.7%
TOTAL CORE COMMERCIAL SALES	111,910	mtherms	57.795	64,678	60.426	67,622	2.631	4.6%
Plus Transport Volumes	3,762	mtherms						
TOTAL CORE SALES	443,374	mtherms	56.085	248,668	58.851	260,931	2.766	4.9%

Rates reflect 1992 attrition allowance.

TABLE 2

SAN DIEGO GAS & ELECTRIC COMPANY
NONCORE RATES AND REVENUES

Effective January 1, 1992

CUSTOMER CLASS		THROUGHPUT	UNITS	EFFECTIVE 8/1/91 PRESENT RATES	EFFECTIVE 8/1/91 TOTAL REVENUES	EFFECTIVE 1/1/92 ADOPTED RATES	EFFECTIVE 1/1/92 TOTAL REVENUES	RATE CHANGE	PERCENT CHANGE
				C/THERM	($000)	C/THERM	($000)	C/THERM	%
COMMERCIAL/INDUSTRIAL									
Volumetric Charge	Winter	25,328	mtherms	18.245	4,652	17.721	4,519	(0.524)	-2.9%
	Summer	42,280	mtherms	12.988	5,528	14.247	6,064	1.259	9.7%
Customer Charges:									
0 to 3,000 therms		0	$/Month	9	0	11	0	2	20.0%
3,001 to 7,000 therms		0	$/Month	46	0	55	0	9	20.0%
7,001 to 23,000 therms		108	$/Month	84	9	101	11	17	20.0%
23,001 to 126,000 therms		455	$/Month	168	77	202	92	34	20.0%
126,001 to 1,000,000 therms		98	$/Month	337	33	405	40	68	20.0%
Over 1,000,000 therms		0	$/Month	716	0	860	0	144	20.0%
TOTAL COMMERCIAL/INDUSTRIAL SALES		67,608	mtherms	15.234	10,299	15.865	10,726	0.631	4.1%
COGENERATION									
Volumetric Charge	Winter	53,751	mtherms	12.928	6,999	12.043	6,520	(0.885)	-6.8%
	Summer	106,699	mtherms	8.468	9,101	9.566	10,281	1.098	13.0%
Customer Charges:									
0 to 3,000 therms		269	$/Month	10	3	15	4	5	49.9%
3,001 to 7,000 therms		205	$/Month	55	11	82	17	27	49.9%
7,001 to 23,000 therms		243	$/Month	100	24	150	37	50	49.9%
23,001 to 126,000 therms		320	$/Month	200	64	300	97	100	49.9%
126,001 to 1,000,000 therms		115	$/Month	400	46	600	69	200	49.9%
Over 1,000,000 therms		39	$/Month	850	33	1,274	50	424	49.9%
TOTAL COGENERATION SALES		160,450	mtherms	10.149	16,283	10.642	17,075	0.494	4.9%
UTILITY ELECTRIC GENERATION									
Demand Charge		12	Cust-mth	$1,915	22,980	$2,453	29,435	538	28.1%
Volumetric Charges:									
Igniter Fuel		2,527	mtherms	30.283	765	40.439	1,022	10.156	33.5%
Tier I	Annual	78,549	mtherms	7.666	6,022	6.479	5,090	(1.187)	-15.5%
Tier II	Annual	346,040	mtherms	3.781	13,084	2.862	9,905	(0.919)	-24.3%
TOTAL UEG SALES		427,116	mtherms	10.033	42,851	10.642	45,452	0.609	6.1%
NONCORE TRANSMISSION SALES		655,174	mtherms	10.598	69,433	11.181	73,253	0.583	5.5%
NONCORE PROCUREMENT									
Retail Core-subscription		2,880	mtherms	26.454	767	19.399	559	(7.055)	-26.7%
Retail Noncore		158,238	mtherms	22.809	36,348	22.809	36,093	0.000	0.0%
UEG Noncore		427,116	mtherms	22.255	95,055	22.255	95,055	0.000	0.0%
NONCORE PROCUREMENT SALES		588,234	mtherms	22.469	132,170	22.390	131,706	(0.079)	-0.4%
TOTAL NONCORE SALES					201,603		204,959	3,355	1.7%
TOTAL RATE REVENUES					450,271		465,890	15,619	3.5%

Rates reflect 1992 attrition allowance.

5A

A.91-03-039
D.91-12-075

Norman D. Shumway, Commissioner, dissenting:

I dissent from the majority's decision. Although I agree with much that is in the decision, I cannot agree to a continuation of the flat allocator system which places a disproportionately high share of administrative and general (A&G) costs on the non-core customers of SoCalGas. There is ample evidence, introduced in the evidentiary hearings in this proceeding, that non-core gas customers are paying an unfairly high bill under the present allocation system. In my judgment, it is reasonable to move, now, toward an equitable distribution of A&G costs by shifting a portion of those costs from the non-core to the core.

To that end, I support a change from the present system which classifies 50% of A&G expenses as commodity-related, allocating them on an equal cents per therm basis, and classifies the remaining 50% in the same manner as Operations and Maintenance (O&M) expenses. I support the 60:40 allocation recommended by Administrative Law Judge (ALJ) Barnett in the proposed decision. A limited reallocation from 50:50 to 60:40, which is significantly less than the 84:16 which SoCalGas proposed, is an appropriate and cautious interpretation of the record established in this BCAP. Such a reallocation is in keeping with the Commission's stated policy of continuing to move toward cost-based pricing.

ALJ Barnett's proposal to move slowly towards the correct allocator by moving from a 50:50 to a 60:40 allocation, now, would have shifted approximately 12 million dollars from the non-core to the core. This translates to an approximately 3/10 of a cent per therm increase to the core and 2/10 of a cent per therm decrease for the non-core. To a non-core customer who uses billions of cubic feet of gas per year in this state, these savings are significant.

I am troubled that the majority's decision, which retains the current 50:50 allocation, takes a step which is inconsistent with the Commission's policy of pricing gas delivery services accurately so that those who incur the costs pay for them. The majority's action leaves in place an unjustifiable burden on industrial users. I think it is particularly critical for us to be aware that employers are making an exodus from California to other states, in part because they can find cheaper energy available elsewhere. I believe we cannot needlessly wait to take the steps necessary to protect our industrial and manufacturing base.

Moreover, the advantage to the non-core of moving from a 50:50 to a 60:40 allocator at this time would have been free of any corresponding "rate shock" for the core. By today's decision all SoCalGas customers will receive rate reductions; this would also have been true under the proposed decision. A shift to the 60:40 allocator would have meant, in most cases, a difference of less than $5 per month to a commercial core customer. For residential customers, shifting the overhead allocators toward the core, who require the most overhead to serve, would still have saved 5% from last year's average monthly bill, considering that other costs have come down.

Many parties have argued that the A&G study which SoCalGas submitted in this BCAP is less comprehensive than that ordered in D.87-05-046 and therefore provides insufficient support for reallocation of A&G costs now. I concur with ALJ Barnett that the record before us does not lead to that conclusion. While the study may not permit us to ascertain with precision what the ultimate allocation between the non-core and the core should be, the study provides substantially more information than we had before us when we issued D.87-05-046, which declined to reallocate A&G costs. In my mind, the evidence before us now is decisive -- the 50:50 allocation is inequitable. Even DRA, who opposed our acceptance of the SoCalGas study and the 84:16 reallocation proposed, recommended that if we accept the study, we allocate A&G costs on a 60:40 basis.

I strongly support, with my colleagues, the expeditious resolution of our gas long run marginal cost (LRMC) proceeding, I.86-06-005, which has languished before the Commission for too many years already. I support the majority's commitment to address the allocator issue as well as a host of other cost issues in that proceeding. I am well aware, moreover, that some parties have argued that the LRMC proceeding, and not a utility-specific BCAP, is the appropriate forum for considering and resolving the issue of A&G cost reallocation. I believe that the position may have merit, to the extent that it is based upon a desire to maximize regulatory efficiency and achieve uniformity. However, on the basis of the persuasive record established in this BCAP and the delays to date in the LRMC proceeding, I believe a heightened pragmatism is required of us. As this recession deepens, I feel strongly that removing costs which don't belong on industry's bill is critical if California is to stay competitive and retain an industrial base.

For the reasons discussed above I believe it would have been timely to act now, it would have been equitable to act now, and it would have been good policy to act now. I would have preferred to take one small step in the right direction today rather than require non-core customers to wait another year to finally get an accurate bill.

Norman D. Shumway

NORMAN D. SHUMWAY
Commissioner

December 20, 1991
San Francisco, California

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director